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September 16, 2014 **PUBLIC DOCUMENT**

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: **Review of the 2012-2013 Annual Automatic Adjustment Reports**
Docket No. E999/AA-13-599

Dear Dr. Haar:

Minnesota Rules 7825.2800 through 7825.2830 require natural gas and electric utilities implementing automatic adjustments in the recovery of fuel purchases to file annual automatic adjustment reports.

Attached is the Minnesota Department of Commerce, Division of Energy Resource's (Department or DOC) *Review of the 2012-2013 Annual Automatic Adjustment Reports* for rate-regulated electric utilities in Minnesota (FYE13 AAA). Each electric utility discussed in this report is being sent a public version. A trade secret version specific to each utility is being sent via electronic mail to the respective utilities.

The Department is available should the Minnesota Public Utilities Commission (Commission) have any questions about the FYE13 electric AAA herein provided.

Sincerely,

/s/ NANCY A. CAMPBELL
Financial Analyst

/s/ SAMIR OUANES
Rates Analyst

NAC/SO/lt
Attachments

REVIEW OF 2012-2013 (FYE13)
ANNUAL AUTOMATIC ADJUSTMENT REPORTS

FOR ELECTRIC UTILITIES

SUBMITTED TO THE
MINNESOTA PUBLIC UTILITIES COMMISSION

DOCKET NO. E999/AA-13-599

SEPTEMBER 16, 2014

PUBLIC DOCUMENT

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I. OVERVIEW

This report summarizes the Division of Energy Resources of the Minnesota Department of Commerce's (DOC or the Department) review of the automatic adjustment charges for the July 2012 - June 2013 (FYE13) reporting period, which were filed by five Minnesota electric utilities in compliance with Minnesota Rule 7825.2810. The Department offers recommendations to the Minnesota Public Utilities Commission (Commission) regarding the information contained in this report, which are summarized at the end of the report.

The utilities included in this report are:

- Dakota Electric Association (Dakota or DEA);
- Interstate Power Company – Electric Utility (Interstate Electric);
- Minnesota Power (Minnesota Power or MP);
- Otter Tail Power Company (Otter Tail or OTP); and
- Northern States Power Company d/b/a Xcel Energy, Incorporated – Electric Utility (NSP or Xcel Electric).

The five rate-regulated electric utilities required to provide information per Minnesota Rules filed the information necessary to meet their filing requirements.[1]

The Department's review focused on whether the electric utilities had, during the period of July 1, 2012 to June 30, 2013, accurately adjusted their energy rates to reflect changes in fuel costs.

The Department also analyzed the utilities' procurement policies, dispatching procedures, cost-minimizing efforts, adjustment computations, and auditors' reports. The FYE13 reporting period coincides with the eighth full year of operation under the "Midcontinent Independent System Operator's Day 2 Energy Market" (MISO Day 2 Market). The Department dedicates Section VIII of this report to addressing MISO Day 2 Market issues.

In addition, the Department also notes in Section IV of these comments that its upcoming reply comments in Docket No. E999/AA-12-757 discusses the overall effectiveness of the automatic adjustment rate mechanism in ensuring that electric utilities take appropriate steps to minimize fuel costs in daily operations and in planning for future needs for the utilities' systems. The Department discusses this issue given concerns about utilities' efforts to minimize fuel costs, or sometimes even to consider fuel costs in planning for future needs.

[1] The Commission granted Northwestern Wisconsin Electric Company (NWEC) a variance from the annual reporting requirements in Minnesota Rules 7825.2800 through 7825.2840 in its Order dated December 18, 2001 in Docket No. G,E999/AA-00-1027. Since the Commission granted this variance with no expiration date, it continues until revoked by the Commission.

II. FILING REQUIREMENTS

A. MINNESOTA RULES

Pursuant to Minnesota Rule 7825.2810, subpart 1, the filing requirements for electric utilities include the following:

- Paragraph A – the base cost of fuel approved by the Commission in the utility's most recent rate case;
- Paragraph B – billing adjustment amounts charged to customers for each type of energy cost, such as nuclear, coal, or purchased power;
- Paragraph D – total cost of fuel delivered to customers;
- Paragraph E – revenues collected from customers for energy delivered; and
- Paragraph G – amount of refunds credited to customers.[2]

Each reporting utility computed billing adjustments and total fuel costs on a system-wide basis. This approach is consistent with the methods used in the monthly fuel clause adjustment (FCA) filings, and the Commission approved this approach in previous proceedings. Therefore, the Department concludes that the Annual Automatic Adjustment Reports (AAA Reports) from all five reporting electric utilities comply with the Commission's filing requirements, as described in Minnesota Rule 7825.2810, subpart 1.[3]

Further, Minnesota Rule 7825.2820 requires the following:

> By September 1 of each year, all gas and electric utilities shall submit to the commission an independent auditor's report evaluating accounting for automatic adjustments for the prior year commencing July 1 and ending June 30 or any other year if requested by the utility and approved by the commission.

All electric utilities submitted auditors' reports in compliance with Minnesota Rule 7825.2820. The Department reviewed each auditor's report filed and notes that there were no exceptions indicated by the auditors.

Minnesota Rule 7825.2830 requires all electric utilities to "submit to the commission a five-year projection of fuel costs by energy source by month for the first two years and on an annual basis thereafter." All utilities complied with this requirement.

Minnesota Rule 7825.2840 requires all electric utilities to "provide notice of the availability of the reports defined in parts 7825.2800 to 7825.2830 to all interveners in the previous two general rate cases." All utilities complied with this requirement.

[2] Paragraphs C and F pertain to natural gas utilities.
[3] In the discussion of allocations throughout this report, the Department notes that the two categories to which costs and revenues are allocated are retail customers and wholesale transactions. Allocations to retail customers are reflected directly in FCA rates, whereas allocations to the wholesale sector may or may not be reflected in rates charged to wholesale customers. For purposes of the ratemaking elements of this report, it is helpful to think of "wholesale transactions" as being similar to shareholders or another non-jurisdictional entity.

In the next section, the Department summarizes the fuel cost projections submitted by each of the electric utilities that made annual fuel cost filings.

B. SUMMARY OF FUEL COST PROJECTIONS

Dakota does not own generation and transmission resources, and instead purchases its power from Great River Energy, its wholesale generation and transmission provider; thus, the figures for Dakota are not directly comparable to the projections for other utilities. Dakota projects that its purchased power (energy and capacity) costs will **[TRADE SECRET DATA HAS BEEN EXCISED]**

Interstate Electric projects its energy costs to **[TRADE SECRET DATA HAS BEEN EXCISED]**

Minnesota Power projects its energy costs to **[TRADE SECRET DATA HAS BEEN EXCISED].**

Otter Tail projects its energy costs to **[TRADE SECRET DATA HAS BEEN EXCISED]**

Xcel Electric projects its energy costs, including fuel, purchases and sales to **[TRADE SECRET DATA HAS BEEN EXCISED]**

These fuel cost projections are summarized in a table in Attachment E1.[4]

III. COMPLIANCES

The Department addresses the reports listed below in this section. The Department notes that the analysis of compliances related to the MISO Day 1 and Day 2 markets are discussed in Section VII *Effects of the MISO Day 1 Market on Minnesota Ratepayers* and in Section VIII *Effects of the MISO Day 2 Market on Minnesota Ratepayers.*

- Investigation of Xcel Electric's Practices Regarding Energy Marketing and the Fuel Clause in Docket No. E002/CI-00-415.

- Natural Gas Financial Instruments (Xcel Electric's compliance filing) in Docket Nos. E002/M-01-1953 and E999/AA-02-951.

- Wind Curtailment Report (Xcel Electric's compliance filing) in Docket Nos. E002/M-00-622 and E002/M-02-51.

- FCA Settlement Agreement (Xcel Electric's compliance filing) in Docket No. E002/GR-05-1428.

- History of Nuclear Fuel Sinking Fund in Docket No. E002/M-81-306.

- Enbridge Energy Issues in Docket No. E017/M-06-1332.

[4] Dakota and MP provided their data based on a fiscal year while IPL, OTP and Xcel Electric used a calendar year.

- Offsetting Revenues and/or Compensation Received by Investor-Owned Utilities (IOUs) (Docket Nos. E002/M-08-1098, E002/M-10-486 and E999/AA-10-884)

- Maintenance Expenses of Generation Plants (Docket No. E999/AA-06-1208).

- Plant Outages Contingency Plans (Docket No. E999/AA-08-995).

- Sharing Lessons Learned Regarding Forced Outages (Docket No. E999/AA-10-884).

- OTP's FCA True Up (E017/M-03-30).

- Curtailment of WM Renewable Energy (Docket No. E002/M-10-161).

- Report on Purchased Power Agreement (PPA) with Manitoba Hydro (Docket No. E015/M-10-961).

- Quarterly Reporting on Accounting Costs of Interstate Electric's ARR (Docket No. E001/M-09-455).

The Department discusses each of these items below.

A. INVESTIGATION OF XCEL ELECTRIC'S PRACTICES REGARDING ENERGY MARKETING AND THE FUEL CLAUSE IN DOCKET NO. E002/CI-00-415

In its Order dated June 15, 2001, in Docket No. E002/CI-00-415, Ordering Paragraph No. 2, the Commission required Xcel Electric to provide a monthly comparison of generation costs allocated to retail and wholesale customers for the months of June, July, and August with its AAA report to ensure that the Company is reasonably allocating generation costs between retail and wholesale customers. Xcel Electric included this data for the first time in its annual reporting filings on September 4, 2001 in Schedule 2 of Attachment G. Xcel Electric also provided this data in its annual reporting filings for all years to date.

In its filing for FYE13, the monthly generation costs allocated to retail and wholesale customers was provided for the above-stated months of 2013.[5] Xcel illustrated its monthly comparison of generation cost allocation between retail and wholesale classes for the months of June, July and August of 2013.

The Department reviewed Xcel's monthly comparisons of generation costs allocated to retail customers and the wholesale sector, and noted that the information filed by the Company appears to comply with the requirements of the Commission's Order. Xcel's data indicated that for all three months in 2013, the retail average generation costs were less than the average generation costs allocated only to the wholesale sector, and less than the average costs for the combined wholesale and retail customers.

The Department notes that a high-level check of the allocations between retail and wholesale customers remains helpful to ensure that lowest cost resources are assigned to

[5] This information was provided in part as Part H, Section 2, Schedule 1 in the initial filing of Docket No. E999/AA-13-599 on September 4, 2013, and was subsequently provided in full in a supplemental filing in the same Docket on October 11, 2013.

retail customers moving forward. Based on our review of the 2013 data, the Department recommends that the Commission approve Xcel Electric's compliance filing on the high-level cost allocation test between wholesale and retail customers for June, July, and August of 2013. The Department recommends that the Commission continue to require Xcel Electric to report this generation cost allocation data in future AAA filings.

B. NATURAL GAS FINANCIAL INSTRUMENTS: XCEL ELECTRIC'S COMPLIANCE FILING IN DOCKET NO. E002/M-01-1953 AND E999/AA-02-951

On March 20, 2002 in Docket No. E002/M-01-1953, the Commission approved a request by Xcel Electric for accounting treatment and related processes necessary to separate the cost accounting for natural gas financial instruments purchased to meet the needs of jurisdictional retail electric and natural gas customers from the natural gas financial instruments purchased to support Xcel Electric's non-jurisdictional wholesale electric sales activities. With Commission approval, Xcel Electric proposed to submit a written request that their external auditors specifically examine these transactions in preparation of the auditor's report to be submitted with Xcel Electric's FYE02 electric and natural gas AAA reports and PGA true-up to be filed September 1, 2002, to ensure that the accounting separation is implemented appropriately.

Xcel Electric's FYE13 AAA report also includes a copy of the prescribed letter by Xcel Electric to its external auditors.[6] The report included a copy of the Deloitte & Touche, LLP Independent Auditors' Report,[7] which concluded: "In our opinion, the accompanying Schedule presents, in all material respects, the accounting for the FCA of the Company for the period from July 1, 2012 to June 30, 2013 in accordance with the Riders and Dockets approved by the Commission."
The Department recommends that the Commission accept Xcel Electric's Natural Gas Financial Instruments compliance filing in the FYE13 docket. The Department intends to review Xcel Electric's continued compliance with this requirement in the FYE14 AAA report.

C. WIND CURTAILMENT REPORT

In the past, various Commission Orders emphasized reporting and regulatory review of the curtailment practices used by Xcel Electric in connection with its wind PPAs. The Department notes that our report in E, G999/AA-05-1403 described the background connected with this issue.

> The Department has continued to monitor the reasons for Xcel Electric's curtailments in monthly automatic adjustment filings. According to these reports, nearly all curtailments have been due to lack of firm transmission or due to directives from MISO pertaining to transmission. The Department notes that an extensive review of Xcel Electric's curtailment in previous years is available in Docket No. E, G999/AA-04-1279.

[6] See Part F, Section 1 of Xcel Electric's FYE13 AAA report.
[7] See Part F, Section 2 of Xcel Electric's FYE13 AAA report.

For this report, the Department concludes that Xcel Electric is substantially in compliance with the Commission's April 4, 2006 Order *Adopting Treatment of Curtailment Payments to Wind Developers through FCA and Requiring Compliance Filings* in Docket No. E999/AA-04-1279. In particular, Xcel Electric included in its FYE13 AAA filing a report of its projected curtailment payments over the next five years related to wind for planned and existing projects and any commitments made to update the system.[8]

Xcel Electric stated that:

> The Company is participating in the development of the CapX2020 transmission projects (CapX) which include a number of projects that will positively impact transmission capacity and wind curtailment on the NSP system. These CapX transmission projects are listed in the following table.
> …
> The CapX transmission lines will increase the capacity of the bulk power transmission system and thus remove impediments to the delivery of power from wind farms around the region. The CapX Brookings County to Twin Cities 345 kV line is expected to increase the transmission limit in southwest Minnesota to 1,950 MW when it is completed in 2015.
>
> In addition to transmission projects developed by the Company, MISO has identified and approved 242 new transmission infrastructure projects including 17 Multi-Value Projects (MVPs) which are designed to accommodate the planned and expected generation expansion in the MISO footprint. The MVP projects, particularly the ones listed in the following table, will have a positive impact on Company-owned and PPA wind facilities.
> …

The Department concludes that Xcel Electric is being proactive in addressing the curtailment issue (through the identification of future limits in transmission capacity and ways to address these limits).

The Department reviewed Xcel Electric's wind curtailment data. Curtailment costs have been substantially reduced from their peak during FYE05 from 16.50 percent of the total cost of wind,[9] including curtailments, to 8.32 percent in FYE08, 2.42 percent in FYE09, and 1.68 percent in FYE13.[10]

Based on the discussion above and the corresponding limited amount of curtailment during the July 2012-June 2013 period, the Department recommends that the Commission accept Xcel Electric's FYE13 wind curtailment report (Wind Report).

[8] Part H, Section 5, Schedule 2 of Xcel Electric's FYE13 AAA report.
[9] The total cost of wind refers to the wind projects that are included in Xcel's monthly FCA filings' Wind Reports: Lake Benton I, Lake Benton II, Chanarambie, Moraine, Northern Alternative Energy, Velva, Fenton, FPL Energy Mower County, MinnDakota, Wind Power Partners 1993, Jeffers Wind 20, Ulik, Ewington and Moraine II Wind.
[10] Source: Attachment E2.

D. FCA SETTLEMENT AGREEMENT (XCEL ELECTRIC'S COMPLIANCE FILING IN DOCKET NO. E002/GR-05-1428)

During Xcel's Electric's 2005 rate case (Docket No. E002/GR-05-1428), the Minnesota Chamber of Commerce and the Large Industrial Group entered into an FCA Settlement Agreement with Xcel Electric. The settlement included several commitments by Xcel Electric intended to provide customers with more information and analysis to enhance the ability of customers to plan for and manage volatility in fuel costs. The additional information and analysis included more discussion on Xcel Electric's plans for hedging fuel or energy purchases and more analysis of how Xcel Electric will try to mitigate volatility, cover risks associated with planned outages and optimize congestion cost hedging. The additional information also included a dollar-per-megawatt-hour ($/MWh) price to show the rolling 12-month average cost quarterly based on expected market conditions.

The Department notes that Xcel Electric's FYE13 AAA filing included additional information and analysis to address the FCA Settlement Agreement approved by the Commission in Docket No. E002/GR-05-1428. The Department was not a party to this settlement, and thus invites comments on this information from those who were parties, regarding whether there are any concerns that need to be addressed.

E. HISTORY OF NUCLEAR FUEL SINKING FUND IN DOCKET NO. E002/M-81-306

Pursuant to the Commission's Order dated July 14, 1981 in Docket No. E002/M-81-306, Xcel Electric included the required information in Part H, Section 1 of its FYE13 AAA filing. Xcel's filing provided a history of nuclear fuel interim storage and disposal expenses included in the determination of electric automatic adjustment charges. Xcel Electric shows payments to the Department of Energy (DOE), DOE credits, and beginning and ending balances for disposal costs and permanent disposal costs.

For purposes of background, the following are the four nuclear charges:

- DOE Yucca Mountain Permanent Disposal Costs, which was a 1 mill per kWh fee that was collected via the FCA until it was suspended on May 16, 2014;
- Interim Storage Costs that were collected from ratepayers and then used for Xcel Electric's Prairie Island Dry Cask Storage Project;
- Payments to DOE for process plant enrichment services, where Xcel Electric was overcharged for the period 1986 to 1993, resulting in a $1.7 million refund to ratepayers through the February 2006 FCA; and
- Nuclear Decommissioning Costs, which are collected through Xcel Electric's base rates. Xcel Electric recommended in its decommissioning study in Docket E002/M-11-939 a 36-year decommissioning period and an annual accrual of $11.2 million for decommissioning starting January 1, 2013. The Commission's December 4, 2012 Order approved a 60-year decommissioning period and a $14.2 million annual decommission accrual starting January 1, 2013.

Based on our review of Xcel Electric's Schedule 1 for the FYE13 AAA, which provides a history of nuclear fuel interim storage and disposal expenses, the DOC concludes that there are no significant changes from Xcel Electric's previous FYE12 AAA filing. (Note: suspension of the DOE's 1 mill/kWh fee will slightly reduce FCA costs for Xcel in the subsequent AAA report.) The DOC notes that total permanent disposal costs paid to DOE were $432 million as of June 30, 2013, with annual amounts for recent years ranging from approximately $11.6 to $12.9 million per year, with an average of $12.2 million per year over the past five fiscal years.

The Department notes that Xcel Electric entered into a July 5, 2011 Settlement with DOE regarding DOE's partial breach of its contract to take spent nuclear fuel beginning January 31, 1998. Xcel Electric received compensation from DOE for the following cost categories: a) any additional pool storage and other plant modifications; b) dry cask storage and costs directly related to such storage (e.g. internal labor, overhead, operating and maintenance, and training and security); and c) additional property taxes from the on-site dry cask storage or other plant modifications. The refund amounts, allocations, and other related issues are further discussed in Docket E002/M-11- 807.

On December 16, 2011, the Commission issued its Order approving the first DOE payment to Xcel to be refunded to customers. The DOC notes that a second DOE payment was made to Xcel Electric and was refunded to customers in March 2012. In November 2012 Xcel received its third payment from DOE, and received its fourth payment on November 7, 2013. These DOE refund payments will be placed in Xcel's decommissioning fund as payment for decommissioning costs with excess DOE payments used to offset future decommissioning costs. The Commission allowed Xcel to place funds disbursed by DOE in 2013 in excess of the decommissioning accrual amount into an external escrow account until such time as the Commission further determines the appropriate use for those funds.[11] The fifth and final DOE payment under the settlement will be discussed in the next decommissioning study to determine how the DOE funds will be handled.

The Department notes that the excess DOE funds estimated at $25.737 million are a part of the Rate Mitigation Plan for the 2015 Step rate increase requested by Xcel. Use of the excess DOE funds for the purpose of rate mitigation is addressed by DOC and other parties in the current Xcel Rate Case Docket No. E002/GR-13-868.[12]

The Department recommends that the Commission accept Xcel Electric's compliance filing regarding Xcel Electric's Nuclear Fuel Sinking Fund. The Department intends to continue to monitor Xcel Electric's Nuclear Fuel Sinking Fund in future filings.

F. ENBRIDGE ENERGY ISSUES IN DOCKET NO. E017/M-06-1332

The Commission's Order dated January 16, 2007 in Docket No. E017/M-06-1332 approved an electric service agreement (ESA) between Otter Tail Power and Enbridge Energy. The Commission's Order requires Otter Tail Power to report in its AAA report the following information:

- the amount of incremental energy purchased by Enbridge Energy under the Large General Service (LGS) Rider,
- the retail rate paid by the customer, and
- the retail rate of the energy had System Marginal Energy Pricing been used to determine the retail rate paid by the customer.

[11] December 18, 2013 Order in Docket No. E002/M-11-807
[12] Campbell Opening Hearing Statement on pages 3-4.

As explained in Docket No. E017/M-06-1332, the principal change from the previous ESA to the current ESA was the change from pricing incremental energy in the LGS Rider on a System Marginal Energy Pricing (SMEP) basis to a Fixed Rate Energy Pricing (FREP) basis. These reporting requirements allow for monitoring the impact of the change from SMEP to FREP on Enbridge Energy's electrical usage.

The 2013 data shows that Enbridge Energy continues to purchase a significant amount of incremental energy. Had SMEP been used to determine the rate for the same amount of energy Enbridge Energy purchased for the July 2012 to June 2013 period, Enbridge would have paid less than it paid under FREP. As the Department has concluded in previous AAA reports, the information to date does not suggest that FREP pricing is resulting in higher energy use by Enbridge Energy.

The Department recommends that the Commission accept Otter Tail Power's Enbridge Energy compliance filing in this docket. The Department will continue to monitor this compliance filling in future reports.

G. OFFSETTING REVENUES AND/OR COMPENSATION RECEIVED BY IOUS (DOCKET NOS. E002/M-08-1098, E002/M-10-486 AND E999/AA-10-884)

In its January 29, 2009 Order in Docket No. E002/M-08-1098 (2009 Order), the Commission required Xcel Electric to report in future AAA filings all revenue from any source as a result of a Renewable Energy Purchase Agreement with Koda Energy, and to itemize any such revenue by source and amount.

Xcel Electric stated that "the Company has not received any new revenue as described in this Order."[13] Therefore, the Department concludes that Xcel Electric complied with the 2009 Order.

In its August 26, 2010 Order in Docket No. E002/M-10-486 (2010 Order), the Commission required Xcel Electric to offset its recovery of costs by all revenues the Company receives from any and all sources as a result of Xcel Electric's power purchase agreement with Diamond K Dairy, and to report and itemize any such revenues by source and amount in its annual automatic adjustment reports.

Xcel Electric stated that "this biomass project is not yet in commercial operation."[14] Therefore, the Department concludes that Xcel Electric complied with the 2010 Order.

In its April 6, 2012 Order in Docket No. E999/AA-10-884 (2012 Order), the Commission required the IOUs to report in future AAA filings any offsetting revenues or compensation recovered by the utilities as a result of contracts, investments, or expenditures paid for by their ratepayers. If any offsetting revenues and/or compensation are not credited back to a utility's ratepayers through the fuel clause, the IOUs should clearly identify such revenues or compensation by source and amount and fully justify their action in the relevant AAA filings.

The IOUs indicated that they passed any such offsetting revenues or compensation through the fuel clause. Therefore, the Department concludes that the IOUs complied with the April 6, 2012 Order in Docket No. E999/AA-10-884 (ordering point 8).

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[13] Source: Part H, Sections 1-8, page 5 of 5 of Xcel's FYE13 AAA report.
[14] Source: Part H, Sections 1-8, page 5 of 5 of Xcel's FYE13 AAA report.

The Department will continue to monitor the treatment of offsetting revenues and compensation recovered by the utilities in future filings.

H. MAINTENANCE EXPENSES OF GENERATION PLANTS (DOCKET NO. E999/AA-06-1208)

In its February 6, 2008 Order (2008 Order), the Commission required all electric utilities subject to automatic adjustment filing requirements, with the exception of Dakota Electric, to include in future annual automatic adjustment filings the actual expenses pertaining to maintenance of generation plants, with a comparison to the generation maintenance budget from the utility's most recent rate case.

This requirement stems from the drastic increase in IOUs' outage costs during FYE06 and FYE07.[15] The Commission agreed with the Department and Large Power Interveners that "utilities have a duty to minimize unplanned facility outages through adequate maintenance, and to minimize the costs of scheduled outages through careful planning, prudent timing, and efficient completion of scheduled work." 2008 Order at 5.

These high levels of outages raised the issue of whether the IOUs are spending as much to maintain their generation plants as they are charging their customers in FCA rates which allow for automatic adjustment of rates to reflect increases in costs.

As summarized below, the Department notes that only MP and Xcel Electric are spending more on operation and maintenance (O&M) costs than they are charging to their customers in rates.[16] Rate case and historical averages are calculated based on data provided by IPL, OTP, MP and Xcel.

Table 1: Comparison of Generation O&M Costs

	Test Year	Rate Case	Historical 2010-2012 Average	Difference from Rate Case
IPL	2009	$ 3,779,345	$ 3,390,830	$ (388,515)
MP	2010	$ 33,619,194	$ 44,654,056	$ 11,034,862
Xcel Electric	2013	$ 173,413,367	$175,043,756	$ 1,630,389
OTP	2010	$ 13,142,720	$ 11,307,596	$ (1,835,124)

Due to the link between the level of O&M expenditures on facilities and forced (unplanned and unexpected) outages of facilities, and due to different current ratemaking incentives (incentive to minimize O&M costs between rate cases with little to no incentive to minimize replacement power costs), the Department intends to continue to monitor the IOUs' actual expenses pertaining to maintenance of generation plants, with a comparison to the generation maintenance budget from the IOUs' most recent rate cases in future AAA filings.

[15] Attachment E3 shows that the outage costs have since substantially decreased as a share of energy costs, with the exception of Xcel Electric during FYE12 and FYE13 as a result of the forced outage at Sherco 3.
[16] Attachment E4 provides an annual breakdown of the IOUs' maintenance expenses of generation plants.

I. PLANT OUTAGES CONTINGENCY PLANS (DOCKET NO. E999/AA-08-995)

In its March 15, 2010 Order, the Commission required all IOUs to work with their contractors to identify and develop reasonable contingency plans to mitigate against the risk of delays or lack of performance when contractors perform poorly and increase costs during plant outages.

This requirement stems from the drastic increase in OTP's energy costs in November ($39/MWh) and December 2007 ($51.20/MWh) due to a contractor's failure to perform the contracted work for a planned outage of the Big Stone plant.

In its FYE07 AAA report, the Department requested suggestions from the utilities regarding improving outage-related contracts to better protect ratepayers. In response, the utilities appeared to jointly agree that "while we attempt to include contract terms or performance bonds to indemnify us for delays or lack of performance, requiring a contractor to indemnify us for replacement energy cost is cost prohibitive." (MP's September 29, 2009 reply comments at 9). However, utilities did not provide evidence to support that position.

The Department attempted to generate a useful discussion of ways to ensure that ratepayers were better protected from delays or lack of performance through the lessons learned by the utilities. The Department recommended that utilities, at a minimum, identify and work with contractors that have reasonable contingency plans to alleviate the risk of delays or lack of performance.

While neither OTP nor Interstate Electric addressed working with contractors in their FYE13 reports, Xcel Electric discussed "the lessons learned and the contingency plans developed by the utility to mitigate against future risk of delays or lack of performance, when contractors perform poorly and increase costs during plant outages."

Xcel Electric provided a description of "the accountability measures for vendors/suppliers" it has established to help Xcel Electric "contract with parties for generation plant repair and maintenance services that have a history of performing work safely, reliably and in a timely manner."[17]

While not addressing the issue overall, MP stated the following:

> *Identification and explanation of outage delays*
> During this period, there were no delays or lack of performance by contractors affecting the length of the outages and/or the replacement energy costs.

The Department appreciates the specific information that Xcel Electric provided. Unfortunately, other utilities did not suggest ways to ensure that contractors are held accountable for replacement power costs due to longer-than-expected outages. The Department expects to continue to monitor the IOUs' plant outages contingency plans in future AAA filings.

[17] Part K, Section 3 of Xcel Electric's FYE13 AAA report.

J. SHARING LESSONS LEARNED REGARDING FORCED OUTAGES (DOCKET NO. E999/AA-10-884)

In its April 6, 2012 Order in Docket Nos. E99/AA-09-961 and E999/AA-10-884, the Commission required the IOUs to provide in supplemental filings to their fiscal-year 2011 AAA reports, in Docket No. E-999/AA-11-792, and in future AAA reports, a simple annual identification of forced outages and a short discussion of how such outages could have been avoided or alleviated.

In this docket, Xcel Electric, MP, IPL and OTP provided the required information.

Overall, Xcel Electric stated:

> To improve upon our plant processes and to unify our power plants to achieve operational excellence through accountability, standardization, technical excellence and organizational alignment, the Energy Supply group launched a Generation Operating Model in late 2011. The initiative began with visits to other companies' generation plants located across the county in order to benchmark best practices and learn from other successful plants' operations. The Operating Model is now applied to standardize Energy Supply's business in Operations, Technical Services, and Engineering & Construction.

Xcel Electric described how the Company has more discussions both among generation experts at the Company's annual Xcel Energy Boiler Conference and also in the Operations Council with senior management. In addition, Xcel described better information sharing across the Company:

> A recent feature implemented to facilitate sharing lessons learned across all of Xcel Energy's operating companies is a monthly Energy Supply newsletter distributed within Xcel Energy. ...The newsletter highlighted notable successes at Harrington [an Xcel generation plant in Amarillo, Texas], such as a greater use of common work practices and information sharing; standardized tracking and reporting, and increased sharing of technical ideas and resources to implement best practices. Lessons learned during the overhaul noted in the newsletter include the need to clarify roles and responsibilities; the need for more detailed planning and scheduling before shutdown of the unit; the need for thorough equipment inspections during an overhaul; and Improved communication and engagement. To further learn from experiences, a link to video taken during the overhaul process was posted and made available to all Energy Supply staff. These lessons learned are being applied across the Xcel Energy system to improve our processes during maintenance overhauls, to work more cohesively as an Energy Supply team and to improve fleet performance.

Xcel Electric also stated that they "continue to participate in industry forums (such as EEI) and monitor electric industry trade materials and studies (*e.g.*, by EPRI) to seek to learn the successful practices of other utilities in handling both planned and forced outages." The Department greatly appreciates that Xcel Electric is taking these issue to heart and making improvements across the Company, which seems appropriate after the longer-than-expected outage at Sherco 3.

The Department requests that Xcel Electric and other utilities discuss in reply comments how Minnesota and other utilities can share best practices across utilities in a timely manner (e.g. videos as Xcel describes, electronic bulletins of best practices) to ensure that as many generation plants as possible maximize the days of operation and minimize the number of forced outages. For example, utilities should discuss any electronic databases that have been developed to share best practices in plant maintenance and repair.

Regarding human performance and vendors, Xcel Electric discussed initiatives to hold employees and contractors more accountable and to provide more oversight of the quality of contractor performance. While these efforts appear to be reasonable, the Department requests that Xcel Electric and other utilities discuss in reply comments when any specific changes have been made in the language of contracts with outside entities to hold those entities accountable for longer-than-expected outages. If no such changes have been made, utilities should explain why not.

OTP stated that:

> Tube leaks in coal-fired boilers are a fact of operation due to the extreme environment (boiler tubes have temperatures of 2000 degrees Fahrenheit on the outside with 600 to 1000 degree water/steam on the inside operating at up to 3000 psi). … Soot blowing, or cleaning of the boiler tubes by using steam, can lead to erosion of the tubes and ultimately to tube failures, but this process is necessary to maintain heat transfer efficiency and to prevent plugging. The level of soot blowing is a function of the ash characteristics of the fuel used at the plant. Lignite fuel (used at Coyote Station), for example, requires more soot blowing than sub bituminous coal (used at Hoot Lake and Big Stone Plants).

The Department does not dispute that tube leaks are "a fact of operation" or that some fuels are more likely to cause unplanned outages, or that "despite improvements, unplanned loss of capacity will occur when dealing with systems as complex as electric generation systems," but requests that utilities explain in reply comments their efforts to obtain Business Interruption Insurance due to such occurrences or to any factor that causes an unplanned outage. If utilities have not obtained any such insurance, utilities should fully explain why not.

Otter Tail listed its efforts to address tube leaks:

> Otter Tail also employs numerous other industry standard methods for detecting and preventing tube leaks, including use of ultrasonic thickness testers, ultrasonic listening devices,

> water chemistry, chemical cleaning, soot blower pressure control, gas stream temperature control, boiler cleanliness, tube material, tube overlays, tube shields, tube alignments, and tube replacements.

However, Otter Tail also stated:

> Utilities have migrated from the average standard six weeks of scheduled overhaul per year to up to six weeks of overhaul every three to five years. This will inherently mean more tube leak forced outages, but is usually still a less expensive option in the long run.

The Department requests that utilities provide in reply comments the dates and duration of their scheduled and forced outages by plant since 2001. In addition, the Department requests that utilities other than Xcel Electric (which already provided such information) discuss in general the factors they consider in scheduling planned outages.

MP also listed some of its efforts, but stated that, while MP was "open to sharing lessons learned on a generic basis with the other utilities on an annual basis," "the concept of sharing lessons learned is more attractive in theory than in practice." MP apparently misunderstands this suggestion to share lessons learned as a suggestion that utilities should provide schedules of future outages:

> …sharing best practices regarding planned outages over and above what companies have already described in public filings borders on releasing confidential information about outage planning and energy marketing. This could work to harm that utility's customers if it were made available to other parties, since those practices provide the utility its best protection in acquiring replacement energy at the lowest cost possible.

Certainly, the goal is not for utilities to release confidential information. Instead, the goal is for utilities to share information about best practices to allow more generators to avoid forced outages so that, when forced outages occur for one utility, there will be more supplies of electricity from other suppliers, thereby reducing the cost of replacement power for the utility with the forced outage.

The Department believes that utilities could reduce the costs that ratepayers pay for longer-than-expected plant outages by holding contractors more accountable for errors and delays, and by exploring insurance options.

Therefore, while the Department concludes that the IOUs complied with the April 6, 2012 Order in Docket No. E999/AA-10-884 (ordering point 22) in reporting information, the Department requests that utilities provide the following in reply comments to identify solutions to issues:

- How Minnesota and other utilities can share best practices across utilities in a timely manner (*e.g.*, videos as Xcel describes, electronic bulletins of best practices) to ensure that as many generation plants as possible maximize the days of operation and minimize the number of forced outages.

- Utilities should discuss any electronic databases that have been developed to share best practices in plant maintenance and repair.
- Utilities should discuss their efforts to obtain Business Interruption Insurance due to any factor that causes an unplanned outage or longer-than-expected planned outages.
- If utilities have not obtained Business Interruption Insurance, they should provide a full explanation as to why not.
- Utilities should discuss any revisions of language in contracts with contractors working on plants to increase the contractor's accountability in minimizing the length of the outage and ensuring that the plant runs smoothly.
- Utilities should discuss any efforts to recoup replacement power costs from contractors that worked on plants that subsequently had outages, or any other source of reimbursement for replacement power costs.
- If utilities did not pursue any reimbursement for replacement power costs, utilities should provide a full explanation as to why not.
- Utilities should provide the dates and duration of their scheduled and forced outages by plant since 2001.
- Utilities should discuss the general factors utilities consider in scheduling planned outages.

K. FCA TRUE-UP REPORT IN DOCKET NO. E017/M-03-30

In its Order dated December 27, 2006, the Commission provided specific true-up procedures applicable to the Otter Tail's annual true-up filings.

Regarding this reporting period, on July 31, 2013, Otter Tail submitted a compliance report and proposal to implement a true-up credit of $0.0002 per kWh. In Comments filed on August 14, 2013, the Department recommended that the Commission approve Otter Tail's compliance report and the true-up credit. The Commission's October 18, 2013 Order approved Otter Tail's true-up increase in rates beginning September 1, 2013.

L. CURTAILMENT OF WM RENEWABLE ENERGY (DOCKET NO. E002/M-10-161)

In its April 30, 2010 Order (2010 Order) in Docket No. E002/M-10-161, the Commission required Xcel Electric to report on any curtailment of wind energy from WM Renewable Energy, including the reasons for any such curtailments and the amounts paid, in Xcel Electric's monthly fuel clause adjustment filings.

Xcel Electric stated that "the Company is not aware of any curtailments or curtailment payments during the current reporting period."[18] Therefore, the Department concludes that Xcel Electric complied with the 2010 Order.

[18] Source: Part H, Sections 1-8, page 5 of 5 of Xcel Electric's FYE13 AAA report.

M. REPORT ON MP'S PPA WITH MANITOBA HYDRO (DOCKET NO. E015/M-10-961)

The Commission's Order in Docket No. E015/M-10-961 required MP to provide in its annual AAA report information regarding the number of times certain energy products were offered by Manitoba Hydro to MP, the number of times such offers were accepted, and various energy price comparisons. The purpose of the data is to assess whether the costs of the Manitoba Hydro products are least cost.

Based on the Department's review of MP's AAA annual report, the Department concludes that MP is in compliance with the Commission's Order in Docket No. E015/M-10-961. MP's information indicates that costs of Manitoba Hydro products were least cost during this reporting period.

N. QUARTERLY REPORTING ON ACCOUNTING COSTS OF INTERSTATE ELECTRIC'S ARR (DOCKET NO. E-001/M-09-455)

The Commission's Order in Docket No. E-001/M-09-455 required Interstate Electric to file the same quarterly reporting regarding the costs and benefits of transactions involving Auction Revenue Rights (ARR) that it files with the Iowa Utilities Board pursuant to the Board's *Order Granting Addendum to Waiver and Requiring Quarterly Reports* (March 11, 2009) in Docket No. WRU-2009-0011-0150.

In accordance with the quarterly ARR transaction reports established with the October 2, 2009 Commission Order in Docket No. E-001/M-09-455, the Department requested information from Interstate Electric regarding the accounting of costs associated with ARR to confirm the flow of ARR transactions through the FCA. The Company responded to the information requests with data confirming the inclusion of ARR transactions in the MISO charge types that are included with the FCA line item "FTR Transaction."

Additionally, the Department notes an erratum filed by the Company that indicated that approximately $1.9 million in low-load ARR proceeds were not properly credited back through the FCA during the specific months falling under the MISO 2012/2013 planning year, and will be credited back to customers as a make-whole payment in Interstate Electric's September and October 2014 FCA factors.[19]

The Department requests that Interstate Electric provide clarification regarding the crediting back of these aforementioned costs, with regard to the costs described in Interstate's response to DOC IR 4 in which the Company notes the accidental omission of revenues from quarterly reports for the period between June 2012 and May 2013. The Department wishes to know if these accidental omissions are related to one another, or if they are separate issues. Further, the Department requests that Interstate Electric show that these refund amounts have been correctly calculated and refunded to customers.

The Department recommends that the Commission accept Interstate Electric's compliance with the Order in Docket No. E-001/M-09-455. The Department will review Interstate Electric's continued compliance with this requirement in the FYE14 AAA report.

[19] Interstate Power and Light Company, Docket No. E001/M-09-455 Revised Quarterly Report, submitted August 27, 2014.

IV. FCA MECHANISM

In the FYE11 AAA docket, the Department conducted an extensive audit of utilities' forced (unexpected) outages, assessing the extent to which utilities took reasonable steps to avoid such outages or minimize costs of replacement power (which are passed on to ratepayers through the FCA).[20] In its December 12, 2012 response comments, the Department made several recommendations regarding recovery of replacement power costs during the forced outages.[21]

On August 16, 2013, the Commission concluded that the "record in this docket does not contain detail sufficient for the Commission to resolve disputes of fact necessary to finally determine the prudence of the utilities' plant operation and maintenance."[22]

The Department's FYE11 investigation of forced outages for the IOUs highlighted the lack of incentive by the IOUs to minimize energy costs. The Department concluded that the IOUs appear to act as if their ratepayers, not the IOUs' management and/or shareholders, should be held accountable for the costs of forced outages even when the outages are the result of a utility's employee errors or outside vendors' mistakes. The Department's investigation also highlighted the inherent difficulties the Commission faces in attempting to resolve disputes of fact, the resolution of which is necessary to determine the prudence of the IOUs' plant operation and maintenance.

As discussed further in the Department's June 5, 2013 comments and follow-up reply comments to be filed before the end of this year in Docket No. E999/AA-12-757, the Department recommends consideration of alternative ratemaking approaches to holding utilities accountable for replacement power costs. This approach is also intended to encourage utilities to consider all costs in providing service, including replacement power costs, in short-term and long-term planning. This report will discuss:

- Original reasons for and cautions about the FCA,
- How the bases for and oversight of the FCA changed over time,
- How these factors are affecting ratepayers.

V. SHERCO 3

One important point to note about Xcel Electric's recovery of costs during this period is the highly unusual, lengthy outage at the Sherburne County Generating Station Unit 3 (Sherco 3) as a result of the catastrophic event of November 19, 2011 (Event). This issue has been discussed extensively in Xcel Electric's most recent rate case.[23] That case identified that the issue of replacement power costs should be addressed in this proceeding.

The Sherco 3 extended plant outage began on November 19, 2011; Sherco 3 was released for MISO dispatch on October 28, 2013, nearly two years later.[24]

[20] Docket No. E999/AA-11-792.
[21] The Department's basis for each of its recommendations is summarized in Attachment E5.
[22] Source: Commission's Order in Docket No. E999/AA-11-792.
[23] See in particular the Direct Testimony of Xcel Electric witness Ronald L. Brevig in Docket No. E002/GR-13-868.
[24] Source: Xcel Electric's June 30, 2014 Sherco 3 Compliance Filing in Docket Nos. E002/GR-13-868 and E002/GR-12-961.

A significant level of replacement power costs have been charged to ratepayers via Xcel Electric's FCA. Specifically, ratepayers have been charged **[TRADE SECRET DATA HAS BEEN EXCISED]** in additional fuel costs for the period November 2011 to October 2013.[25]

The Department notes that Xcel Electric's FCA filings in December 2013 and January 2014 identified continued outages at Sherco 3 between November 15 and December 30, 2013.[26] As a result, the additional fuel costs due to the Sherco 3 outage increased to **[TRADE SECRET DATA HAS BEEN EXCISED]** [27]

Similar to our analysis of the IOUs' forced outages during FYE11 discussed above, the Department's analysis of the prudency of Sherco 3 outage-related additional fuel costs is based on an assessment of whether Xcel Electric's actions caused the Event and whether Xcel Electric had (or should have had) knowledge about the potential for such an event and learned from past similar "failures" by taking specific preventive steps.

The Department reviewed, and summarizes below in Section A, what caused the Event.

Given that the record to date indicates that the Event may be due to the original design of the finger pinned blade attachments, not by abnormal operating conditions or maintenance practices, the Department discusses in Section B whether Xcel Electric should have learned from past similar failures and taken preventive steps to alleviate the occurrence of the Event or taken other steps to protect ratepayers from the high level of replacement power costs.

A. CAUSE OF THE EVENT

On October 21, 2013, Xcel Electric filed a Root Cause Analysis Report (Report) in Docket Nos. E002/GR-13-868 and E002/AA-13-599. The Report was issued by a consulting firm, Thielsch Engineering, hired by Xcel Electric to investigate the cause of the Event.

According to the Report at 93, the fractures of finger pinned blade attachments in the low pressure turbine L-1 turbine end disk was the origin of the Event:

> The Unit 3 Steam Turbine Generator event of November 2011 was precipitated by the fracture of multiple finger pinned blade attachments in the Low Pressure Turbine "B" turbine end L-1 stage disk rim. The fractures resulted in liberation of portions of the finger pinned blade attachments and associated L-1 blades. The loss of mass, due to the liberation of these blades and disk sections, created a significant imbalance at the affected stage, resulting in high amplitude vibration throughout the steam turbine generator train. This vibration was responsible for the fracture of the generator shaft, fractures of the exciter shaft at three locations and extensive additional damage to the steam turbine generator train and other plant equipment.

[25] Source: Attachment E6.
[26] Source: Attachment 1 of Xcel's monthly FCA filings in Docket Nos. E002/AA-13-1177 and E002/AA-14-103.
[27] Source: Attachment E6.

The Report concluded that these fractures were due to pre-existing caustic stress corrosion cracks at the pin holes, ledges and at the base of the finger pinned blade attachments:[28]

> The fractures of the finger pinned blade attachments in the low pressure turbine L-1 turbine end disk were due to the presence of pre-existing caustic stress corrosion cracks at the pin holes, ledges and at the base of the finger pinned blade attachments. The chemical species responsible for stress corrosion cracking could not be positively identified but sodium hydroxide (NaOH) is suspected. Although the exact age of the stress corrosion cracks could not be determined, it is likely that they initiated a few years ago. The propagation and "linking-up" of the stress corrosion cracks during subsequent operation incrementally reduced the load carrying capability of the finger pinned blade attachments. By November 2011 the load carrying capability of the finger pinned blade attachments had been reduced to the point that they could no longer sustain the centrifugal stresses generated during the planned overspeed test and fractured due to tensile overload. Investigation also revealed numerous similar stress corrosion cracks in the finger pinned blade attachments of the LP "B" generator end L-1 disk and the generator and turbine end L-1 disks of the LP "A" turbine.

The Report concluded that these stresses in the finger pinned blade attachments were solely a function of the original design and operation at design conditions: [29]

> The primary causal factor responsible for the stress corrosion cracking of the low pressure turbine L-1 disks was the high static stresses generated during normal operation at the pin holes, ledges and at the base of the fingers of the finger pinned blade attachments in the low pressure turbine L-1 stage disks. The stresses in the finger pinned blade attachments are solely a function of the original design and operation at design conditions.

According to the Report, there was no evidence of abnormal operating conditions or maintenance practices that would have contributed to the stress corrosion susceptibility of the finger pinned blade attachments in the L-1 disks: [30] The Report stated that: [31]

> The design of the subject low pressure turbine L-1 disk finger pinned blade attachments is concluded to be susceptible to stress corrosion cracking under normal operating conditions and is considered a primary causal factor for the subject fracture of the Unit 3 finger pinned blade attachments in the low pressure "B" turbine end L-1 disk and cracking in Unit 3 finger pinned blade attachments in the low pressure "B"

[28] Source: Report at 93.
[29] Source: Report at 93.
[30] Source: Report at 91-94.
[31] Source: Report at 91.

generator end and low pressure "A" generator and turbine end L-1 disks.

Based on the record to date, the Department concludes that the Event was likely caused, not by abnormal operating conditions or maintenance practices, but by the original design of the finger pinned blade attachments.

B. AVAILABLE INFORMATION

On November 15, 2013, the joint owners of Sherco 3, Xcel Electric and Southern Minnesota Municipal Power Agency (SMMPA), and insurers of Sherco 3 filed a joint complaint against General Electric entities (GE) to recover costs associated with the Event.

On January 27, 2014, the plaintiffs to the case, including Xcel Electric, amended the complaint in response to a motion by the defendants that the plaintiffs make more definitive statements regarding some of their claims. The defendants have since moved to dismiss the complaint on various legal grounds.

A hearing on the motion to dismiss was held on April 17, 2014 and denied on May 6, 2014. Consequently, the litigation will continue. In the interim, the parties have been conducting discovery.

Following discovery, the Department received and reviewed the amended complaint.[32]

The nature of the action by the plaintiffs in this case is described as follows:[33]

1. This lawsuit involves the Low Pressure (LP) turbine of a G3 tandem compound steam turbine (Unit 3) that catastrophically failed on November 19, 2011, at the Sherburne County Generating Station (Sherco) in Becker, Minnesota. General Electric Company and General Electric-related entities designed, marketed, manufactured, and sold the LP turbine and at various times serviced the LP turbine.
2. The LP turbine's catastrophic failure caused substantial damage to Unit 3's other turbines, the generator, the exciter, and other property at Sherco.
3. Plaintiffs' investigations concluded that defendants' acts and omissions, as detailed in this Amended Complaint, caused the LP turbine to fail catastrophically.
4. Plaintiffs seek damages arising from and proximately caused by defendants' grossly negligent, willful, wanton, reckless, and :fraudulent conduct, malpractice and other acts and omissions.

The causes of the action by the plaintiffs in this case are described as follows:[34]

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32 Copy of the Amended Complaint is provided in Attachment E7.
33 Source: page 2 of the Amended Complaint, Attachment E7.
34 Source: pages 19-22 of the Amended Complaint, Attachment E7.

Count I: Fraudulent concealment

65. Before the G3 equipment and machinery that would become Unit 3 were designed and manufactured, General Electric Company knew about the risks associated with SCC in G3 type LP turbines. As time progressed, General Electric Company learned even more about systemic SCC problems in General Electric LP turbines. This knowledge would certainly have been shared with the General Electric related entities that provide technical information to and services for operators of G3 type turbines and similar equipment (as evidenced in TIL 1277-2).

66. Despite that special knowledge, during the sale and thereafter General Electric Company, the "GE" representatives at pre-outage meetings, and the General Electric-related entities performing service on Unit 3 provided incomplete information and withheld information about SCC problems from NSP for itself and as Unit 3 project manager on SMMPA's behalf.

67. Specifically, none of the defendants ever warned NSP for itself and as Unit 3 project manager on SMMPA's behalf that Wilson-Line SCC plagued G3 type LP turbines, even as instances of such problems mounted. General Electric Company went so far as to reassure NSP for itself and as Unit 3 project manager on SMMPA's behalf that proper LP rotor wheel inspections were not necessary "unless abnormal events or operational anomalies occur." This recommendation remained in effect for almost two years after the Unit 3 catastrophic failure.

68. Despite the continued recommendation to conduct magnetic particle testing only upon the occurrence of abnormal operations or "anomalies," information available to General Electric Company, the "GE" representatives at pre-outage meetings, and the General Electric-related entities performing service on Unit 3 (but not to NSP for itself and as Unit 3 project manager on SMMPA's behalf) made the defendants aware that the periodic and proper inspections of the LP rotor wheels, later recommended in TIL 1886, were critical to prevent catastrophic unit failure and worker safety hazards.

69. General Electric was aware of dozens of similar SCC problems that had occurred over several years, many of which certainly occurred before the Unit 3 LP-B rotor wheel failed in November 2011. Nevertheless, General Electric Company intentionally withheld any information related to such failures, intentionally failed to warn about SCC-related risks in LP turbines powered by recirculating boilers, and intentionally failed to inform NSP for itself and as Unit 3 project manager on SMMPA's behalf about how to properly and timely detect SCC on LP turbine rotor wheels.

70. To make matters worse, General Electric Company and General Electric- related entities or personnel withheld information about the new patented rotor wheel dovetail

design, which recognized prior design deficiencies and developed an alternative design that was less susceptible to SCC.

71. Despite being involved in planned Sherco outages, General Electric Company, the “GE” representatives at pre-outage meetings, and the General Electric-related entities performing service on Unit 3 withheld information relating to the defective design of the existing rotor wheels and the potential for catastrophic Unit 3 failure. Despite special knowledge about SCC problems in its LP-turbine the General Electric and General Electric-related entities and personnel kept silent about the risk of failure and the means for detecting SCC while attending pre-outage meetings and submitting bids for work to be performed during Unit 3 outages.

72. Because the General Electric Company, the “GE” representatives at pre- outage meetings, and the General Electric-related entities performing service on Unit 3 withheld information about the need for periodic and proper rotor wheel testing and the potential for catastrophic Unit 3 failure and, in fact, advised NSP for itself and as Unit 3 project manager on SMMPA’s behalf (expressly and through conduct) that such testing was unnecessary, NSP with reasonable diligence could not have discovered the design and manufacturing defects before the failure and ensuing investigation.

73. The General Electric Company, the “GE” representatives at pre-outage meetings, and the General Electric-related entities performing service on Unit 3 knew that NSP for itself and as Unit 3 operator on SMMPA’s behalf relied upon General Electric-related entities technical information and expertise to develop maintenance and inspection plans for the LP turbines. Defendants’ intentional withholding of that information rendered NSP unable to identify and detect the SCC damage that was compromising Unit 3 rotor wheel integrity.

Based on the record to date, the Department concludes that GE had specialized knowledge about the risks of SCC-related failure associated with the finger dovetail (areas where turbine blades are inserted into the rotor wheel) in the LP turbine but failed to share information with Xcel Electric and SMMPA.

As stated in the amended complaint, if this special knowledge had been shared with Xcel Electric and SMMPA, proper turbine inspection and maintenance could have prevented the substantial property damage caused by SCC in the LP turbine.[35]

The amended complaint indicates that Xcel Electric was not aware or informed directly or indirectly about the risks associated with SCC in LP turbines.

[35] Source: page 28 of the Amended Complaint, Attachment E7.

The Department notes that the legal process regarding Sherco 3 is likely to take several years to complete. In the meantime, this example raises an important question about the role that Business Interruption Insurance could play. Such insurance is defined as:

> **Business interruption insurance** (also known as **business income insurance**) covers the loss of income that a business suffers after a disaster while its facility is either closed because of the disaster or in the process of being rebuilt after it. A property insurance policy only covers the physical damage to the business, while the additional coverage allotted by the business interruption policy covers the profits that would have been earned. This extra policy provision is applicable to all types of businesses, as it is designed to put a business in the same financial position it would have been in if no loss had occurred.[36]

As noted above, the Department has requested that utilities discuss in reply comments whether they have obtained such insurance and, if not, why not.

Further, during the legal process, additional facts may be developed through either briefs or discovery that are not available to date. Therefore, the Commission may want to retain the right to revisit this issue if additional facts developed during the legal process contradict the record to date.

The Department would like to remind the Commission that it does have the authority to make refunds and changes in allocations between retail and wholesale customers in the AAA filing, based on the review and recommendations by the Department (or other interested parties). The Commission has required refunds and changes in allocations between retail and wholesale customers in the AAA based on the Department's review of the MISO Day 2 charges for several issues. Specifically, the Commission's February 6, 2008 Order in Docket No. E,G999/AA-06-1208 required the following refunds and changes in allocations between retail and wholesale customers:

- Changes in allocations for Revenue Neutrality Uplift and Revenue Sufficiency Guarantee (Ordering Paragraph 3);
- Refunds related to revenues from energy sales in the MISO Real-Time Market (Ordering Paragraph 19); and,
- Refunds related to Asset-Based Financial Transmission Rights Revenues (Order Paragraph 20).

[36] Source: http://en.wikipedia.org/wiki/Business_interruption_insurance

VI. TOTAL FUEL COST REVIEW

A. OVERVIEW

Table 2 summarizes the electric utilities' fuel-cost recovery during FYE13.[37] Xcel Electric's data is highlighted in the calculations below because the Company was granted a variance to charge FCA rates based on Xcel's forecast of fuel costs in the upcoming month, rather than the two-month average cost per kWh required by Minnesota Rules, and the Company adjusts its rates to refund or recover previous over- and under-recoveries of its energy costs through a monthly (2 lag-month) true-up.

Table 2:
Summary of Automatic Fuel Adjustments FYE13

Utility	Fuel Cost Recovered ($)	Fuel Cost ($)	Over-Recovery/ (Under-Recovery) ($)	(%)
DEA	$141,371,168	$140,557,100	$814,068	0.58%
Interstate Electric	$18,203,624	$17,624,531	$579,094	3.29%
MP	$187,342,761	$186,736,616	$606,145	0.32%
OTP	$50,482,963	$50,027,392	455,570	0.91%
Xcel Electric	*$894,345,964*	*$883,488,131*	*$10,478,980*	*1.19%*

To review the electric utilities' calculations of automatic adjustment charges, the Department compared actual costs of fuel purchased during the year to the fuel costs recovered through automatic adjustments.

The Department recognizes that utilities will normally experience small over-recoveries and under-recoveries. In the past, most fuel-cost variations have been caused by fluctuations in weather and by price volatility in the wholesale electric market. Higher-than-anticipated energy demand forces a utility to either generate or purchase additional power. As a result, marginal costs increase as demand increases, typically leading to under-recovery of fuel costs. The reverse is also true: lower-than-expected energy demand can cause fuel costs to fall and lead to over-recovery of fuel costs. The "2 and 3 lag-month" associated with the calculation of most utilities' energy-cost adjustments also leads to unexpected variations, since fuel costs incurred in a given month are recovered in later months.[38] Generator outages and a variety of other supply-side factors can also cause variations in fuel costs.

Prior to actions by the Federal Energy Regulatory Commission (FERC) that deregulated the wholesale market, fluctuations in wholesale prices were small on a month-to-month basis. However, these fluctuations are now much greater than before. As indicated above, the Department notes that the reporting period includes the seventh full year of costs incurred in the MISO Day 2 Market, which began on April 1, 2005. This issue is discussed further below.

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[37] Supporting spreadsheets for FYE13 data with Department's calculations are provided in Attachment E8 (Dakota), Attachment E9 (IPL), Attachment E10 (MP), Attachment E11 (OTP) and Attachment E12 (Xcel Electric).

[38] During the reporting period, Interstate Electric, MP, and OTP used a moving-average process to calculate their energy-cost adjustments. The average costs that these utilities used for their adjustments were calculated using costs that were incurred two and three months prior to the month in which such costs were recovered. As noted above, Xcel Electric did not use this method during the reporting period.

B. DAKOTA ELECTRIC ASSOCIATION

Dakota serves about 101,000 Minnesota electric customers in the southern metropolitan area, in Dakota, Goodhue, Scott and Rice counties. Attachment E8 shows that DEA's resource adjustment includes $140,557,100 in fuel costs, which includes generation capacity and transmission costs from its suppliers, during the reporting period.[39]

Regulated utilities normally recover through their automatic adjustments only changes from the amounts set in a rate case of costs of fuel and energy from purchased power agreements; changes in capacity costs are typically not reflected in fuel adjustment clauses. As an electric cooperative providing only distribution service, however, Dakota requires special consideration because it recovers variations in purchased capacity costs as well as energy costs through the fuel adjustment clause. Ordinarily, the inclusion of these costs increases Dakota's monthly over- and under-recoveries, since purchased capacity costs are not as closely linked to variations in sales as are energy costs. Changes in sales can result in a significant gap between the utility's actual purchased capacity costs per kWh and the purchased capacity costs per kWh built into its base rates. To account for potential discrepancies between its actual and recovered costs through its automatic adjustment, Dakota calculates and applies an annual fuel-cost true-up factor based on these discrepancies.

C. INTERSTATE ELECTRIC

Interstate serves approximately 44,000 electric customers in Minnesota, primarily along the southern edge of Minnesota. As a relatively small electric utility, Interstate's level of fuel costs was $17,624,542[40] in FYE13, slightly higher than the $17,125,241 fuel costs in FYE12.

During FYE13, Interstate recovered $18,203,625 in fuel cost and experienced $17,624,542 in actual fuel cost for an over-recovery of 3.29 percent. Interstate had 7 months in which over- and under-recoveries were in excess of 15 percent. For comparison, in FYE12 Interstate had 9 months of over- and under-recovery above 15 percent, with 5 months in FYE11 and 6 months in FYE10. In FYE13, Interstate experienced an over-recovery of 3.29 percent after experiencing 6.14 percent under-recovery in FYE12 and a 7.90 percent over-recovery in FYE11.

D. MINNESOTA POWER

Minnesota Power serves about 144,000 electric customers in northeastern Minnesota. MP's fuel costs in the FCA were $186,736,616 for FYE13.[41] As shown in Table 2 above, MP over-recovered its fuel costs by $0.6 million in FYE13, or approximately 0.32 percent of its actual costs. By comparison, in FYE12, MP's actual fuel costs in the FCA were $172,309,289, and MP under-recovered by approximately $4.0 million, or 2.32 percent. In FYE11, MP's actual fuel costs in the FCA were $178,139,462, and MP over-recovered by $0.8 million, or 0.47 percent.

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[39] Subject to Commission approval, Minnesota Rule 7825.2600 allows a utility that purchases at least 75 percent of its annual energy requirements to include capacity costs in its energy adjustment. Dakota does not have its own generation. Dakota purchased all its energy needs from power suppliers, Great River Energy (GRE) and Energy Alternatives (EA).

[40] Source: Attachment E9.

[41] Source: Attachment E10.

The Department notes that MP's level of under/over-recovery varies from month to month. In FYE13, MP's monthly under/over-recoveries ranged from a $3.3 million under-recovery in November 2012, to a $2.7 million over-recovery in February 2013.

E. OTTER TAIL POWER COMPANY

Otter Tail serves more than 59,000 Minnesota electric customers, primarily in western Minnesota. During the reporting period, OTP's total fuel costs in the FCA were $50,027,392 for FYE13.[42]

The Department notes that OTP's total fuel costs in the FCA were $46,636,031 for FYE12, resulting in an approximate increase from FYE12 to FYE13 of $3.4 million. The Department noted that the $3.4 million increase appears to be due to increased MISO Day 2 charges as discussed below.

During FYE13, Otter Tail experienced 3 months of over- or under-recovery greater than 15 percent. However Otter Tail only incurred a 0.91% over recovery on FYE13 as a whole.

F. XCEL ELECTRIC

Xcel Electric, which serves about 1.2 million electric customers in Minnesota, primarily in the metro area, had fuel costs in its FCA of $883,488,131 for FYE13.[43]

Xcel Electric is the only electric utility to use a forecasted FCA method.[44] Under this method Xcel Electric bases its monthly FCA on its one-month projection of fuel and purchased power costs. Xcel Electric uses this method in lieu of a forecast based on the average of the most recent two months of known costs as specified by Minnesota Rules. The Commission also allowed Xcel Electric to make an additional adjustment to its forecasted FCA to true-up any over- or under-recoveries of costs that it experienced two months prior to the month in which it applies a new FCA. As a result, unlike electric utilities that calculate their FCA using the method required in the Minnesota rules, Xcel Electric is expected to be better able to reflect current FCA costs in rates closer to the time when these costs are incurred.[45] Moreover, it is expected that Xcel Electric's recovery of costs, in general, will be more closely aligned with costs incurred, with less deviation in cost recovery compared to cost incurrence. It should also be noted that, while Xcel's monthly true-up should ensure that Xcel will recover costs closer to the time when those costs are incurred, it may also result in significant deviations in cost recovery in the month the true-up is implemented and distort information about current fuel costs.

[42] Source: Attachment E11.
[43] Source: Attachment E12.
[44] See the Commission's May 4, 2012 Order in Docket No. E002/M-11-452.
[45] Under the method in the Commission's rules, a utility's cost recovery position may be positive or negative depending on the 12-month time frame selected over which cost recoveries are aggregated.

VII. EFFECTS OF MISO DAY 1 ON MINNESOTA RATEPAYERS

On March 28, 2002, the Commission approved petitions requesting the transfer of functional control of certain transmission facilities to MISO from the following IOUs:

- Xcel Electric, Docket No. E002/M-00-257, Order issued May 9, 2002;
- Interstate Electric, Docket No. E001/PA-01-1505, Order issued May 9, 2002;
- Minnesota Power, Docket No. E015/PA-01-539, Order issued April 26, 2002; and,
- Otter Tail Power, Docket No. E017/PA-01-1391, Order issued May 9, 2002.

These four Minnesota electric investor-owned utility companies were required to provide the information below as part of their AAA report. The Department summarizes the companies' responses to the seven ordering paragraphs as discussed below:

A. THE SCHEDULE 10 ADMINISTRATIVE CHARGES PAID TO MISO UNDER THE MISO TARIFF.

The four Minnesota Electric Utilities provided the following administrative charges, referred to as "Schedule 10 costs," billed by MISO for the period July 2012 through June 2013:

Table 3: MISO Schedule 10 Costs for July 2012 through June 2013

	Total Company	Estimated MN Jurisdiction
Xcel Electric	$10,648,509[46]	$7,911,101
Interstate Power	$2,673,330[47]	$166,816
Minnesota Power	$1,974,896[48]	$1,531,927
Otter Tail Power	$748,917[49]	$358,649
Total	$16,045,651	$9,968,493[50]

The total amount charged to these companies for MISO Schedule 10 costs decreased by $681,597 or 4.07 percent from the previous reporting period. The total estimated Minnesota jurisdictional amount resulted in a decrease of $413,347 or a 3.98 percent decrease from the previous reporting period. IOU's MISO Schedule 10 costs decreased from the previous reporting period except that of Otter Tail Power, which increased by 1.36 percent . OTP indicated that the Company did not see any additional benefits from the increase of these costs.

The Department continues to monitor MISO Schedule 10 costs and expects the four Minnesota utilities in MISO to show benefits related to these costs in their rate cases before

[46] MISO Schedule 10 costs paid by NSP-Xcel consist mostly of Minnesota cost, with some costs for Wisconsin, North Dakota and South Dakota. The Department estimated the Minnesota jurisdiction percentage of 74.29% jurisdictional allocator from Xcel's most recent rate case.
[47] MISO Schedule 10 costs paid by Alliant Energy for IPL for the AAA period. The Department assumed IPL's Minnesota retail jurisdictional percentage at 6.24%.
[48] MISO Schedule 10 costs paid by MP for the AAA period with an average Minnesota retail jurisdictional percentage of 77.57%.
[49] MISO Schedule 10 costs paid by OTP for the AAA period. The OTP estimated Minnesota retail jurisdictional percentage is 47.89%.
[50] Xcel AAA initial filing's Attachment I, Section 1-7, Pg. 2 of 9, OTP AAA initial filing's Attachment A, MP AAA initial filing's Attachment No. 6 and IPL's AAA initial filing's Attachment H provide the Minnesota Jurisdictional MISO Schedule 10 costs.

receiving cost recovery. This recovery and analysis occurs in rate-case proceedings, and has occurred in Xcel Electric's, Interstate Electric's, OTP's and MP's rate cases.

The Department recommends that the Commission continue to require utilities to provide in the initial filing of all future electric AAA reports the Minnesota-jurisdictional MISO Schedule 10 costs, together with the allocation factor used, and support for why the allocator is reasonable. Additionally, the Department recommends that the Commission continue to require the utilities to provide information to support any increases in MISO Schedule 10 costs of five percent or higher over the prior year's costs, including an explanation of benefits received by customers for these added costs. This additional information will expedite the Department's review of MISO Day 1 costs in future electric AAA filings.

B. ANY AMOUNT OF MISO ADMINISTRATIVE CHARGES DEFFERED BY MISO FOR LATER RECOVERY.

This reporting requirement pertains to MISO administrative charges (Schedule 10 costs) that were deferred as regulatory assets for later recovery. At the Department's request, the electric utilities provided the following comprehensive answer to describe MISO's deferred Schedule 10 costs:

> "Transmission Start-up Costs" are MISO operating costs incurred prior to initial start-up that were deferred in accordance with a FERC order. These costs are being recovered over a six-year period from MISO's customers through monthly charges under Schedule 10 of the MISO tariff. The "$0.15 per MWh Rate Cap" asset is for ongoing costs incurred but not recovered under Schedule 10 due to the $0.15 per MWh rate cap in place during the first six years of commercial operations. The rate cap ended on February 1, 2008. The "Current Schedule 10" rates based on forecasted billing units and actual costs for the month are included in subsequent months' rate calculations. These costs are classified as deferred regulatory assets, and will be recovered in a subsequent period.

In a March 26, 2003 compliance filing in response to the FERC's Order accepting a contested partial settlement in Dockets ER02-111 and ER02-652, MISO proposed changes to Schedule 10 to reflect deferral of $25 million of current expenditures that would have been recovered under Schedule 10 in 2003, but which were deferred until February 1, 2008, to be recovered over a five-year period. There are no additional deferrals beyond the $25 million.

During 2003 and 2004, MISO made payments to Grid America, Ameren and Illinois Power. These payments by MISO, net of the exit fees, totaled $40,319,000 and are being amortized over a 10-year period.

The Department included the actual MISO Schedule 10 costs paid by utilities for July 2012 to June 2013 in Table 3 above.

C. EACH INSTANCE WHERE MISO DIRECTED COMPANIES TO CURTAIL THEIR OWN GENERATION, FOR RELIABILITY REASONS, THAT RESULTED IN AN INTERRUPTION OF FIRM RETAIL ELECTRIC SERVICE TO RETAIL CUSTOMERS OF MINNESOTA.

All four utilities indicated that no such instances occurred during the reporting period July 2012 through June 2013.

D. EACH INSTANCE WHERE MISO DIRECTED THE CURTAILMENT OF DELIVERY OF A FIRM PURCHASE POWER SUPPLY THAT SUBSEQUENTLY RESULTED IN AN INTERRUPTION OF FIRM RETAIL ELECTRIC SERVICE TO THE COMPANIES' RETAIL CUSTOMERS IN MINNESOTA.

All four utilities indicated that no such instances occurred during the reporting period July 2012 through June 2013.

E. CHANGES TO MISO TARIFFS THAT MAY ULTIMATELY AFFECT THE RATES OF RETAIL CUSTOMERS TO MINNESOTA, AND ON COMPANIES' EFFORTS TO MINIMIZE MISO TRANSMISSION SERVICE COSTS.

The Companies provided various answers in their MISO Day 1 compliance filings on the effect on retail rates in Minnesota of changes to MISO's tariffs. Specifically:

- During the period July 1, 2012 to June 30, 2013, MISO submitted a significant number of filings to FERC, including proposed tariff changes to the MISO Open Access Transmission Energy and Operating Reserve Markets Tariff (Tariff), compliance filings, generation interconnection agreements subject to the Tariff, answers to complaints, and various other filings. Many of the proposed tariff changes and other filings may ultimately affect rates of retail electric customers in Minnesota in some manner. All MISO filings to FERC during the reporting period are available by month at the MISO web site (www.midwestiso.org) at the "FERC Filings and Orders" quick link. Xcel Electric's Part D, Section 8 in their AAA filing summarizes the MISO filings and other FERC proceedings with the potential for more substantial financial impact on the Company (and thus the rates charged to retail electric customers in Minnesota), and the Company's efforts to minimize MISO costs through its interventions and comments filed at FERC.

- Utilities indicated that they have participated in several ongoing efforts to minimize MISO transmission service cost. They stated that their representatives participated in the MISO Transmission Owners Committee and the Transmission Owners Tariff Working Group, which make decisions on certain rate and revenue distribution changes pursuant to the MISO Agreement. They also stated that they have closely monitored the Market Sub-Committee and OATT Business Practices efforts. Finally, they stated that they have been actively involved in the ongoing Regional Expansion and Cost Benefit Task Force (RECB). They have begun to see cost allocations under the previously approved tariff schedules. MISO, with the support of Transmission Owners, filed changes to the RECB cost allocation process proposing that costs associated with Multi Value Projects (MVPs) be allocated across the entire MISO footprint rather than to nearby pricing zones. FERC approved this filing on December 16, 2010. Projects designated as MVPs are large scale transmission builds required to bring mandated energy (such as renewables) to load. The general consensus is that all loads will benefit from this type of build; therefore, all should share in the cost. MISO has approved the first MVP for cost allocation, "The Michigan Thumb Project," and has given preliminary approval for the second MVP Project, "CAPX 2020 Brookings to Twin Cities Project." Utilities have begun to see charges associated with these projects in 2012.

- MISO has included Schedules 16 and 17 in its Open Access Transmission and Energy Markets Tariff. These schedules are related to MISO's implementation and administrative costs of the MISO energy market. Schedule 16 recovers costs associated with Financial Transmission Rights and Schedule 17 recovers costs associated with the day-ahead and real-time markets. Utilities noted that Schedule 16 and 17 costs have trended downward with expanded MISO membership.

F. AN ANNUAL ANALYSIS OF HOW THE TRANSFER OF OPERATIONAL CONTROL TO THE MISO HAS AFFECTED COMPANIES' OVERALL TRANSMISSION COSTS AND REVENUES AND OVERALL ENERGY COSTS FOR RETAIL CUSTOMERS, INCLUDING:

i. an analysis of how MISO membership has affected Companies' ability to use their own generation sources when they are the least-cost power source; and
ii. Companies' ability to access low-cost power on the wholesale market for their retail customers.

Generally the utilities agreed that the transfer of operational control of transmission to MISO has not had a significant impact on overall transmission costs. The utilities have noted some decreases in transmission revenues; however reduced transmission rates have benefited utilities that need to make energy purchases to serve native load customers. The utilities note that an increase in costs has occurred due to costs charged under Schedule 10, MISO's administrative charges (see discussion in section E.4.a above), but a decrease in costs has occurred due to the elimination of transmission rate "pancaking" and elimination of the MAPP or MAIN fee, which likely results in an slight overall net increase in cost.

The utilities generally agreed that they continue to make use of the wholesale power market to provide low-cost energy for their customers. Utilities also indicated there have been times when they have been able to buy power below base load generation costs to the benefit of ratepayers.

Xcel Electric provided the following response in regard to how MISO has affected Xcel Electric's ability to use its own generation sources when these are least-cost power sources:

> In summary, NSP makes Company-owned and purchased network resources available to the regional dispatch optimization. NSP uses proprietary resource trading methods to ensure the least cost resources remain available for native supply, while ensuring that competitive regional supply alternatives have the opportunity to clear when they can provide energy at lower costs.
>
> In general, operation of the Day 2 market ASM market has not negatively affected the Company's ability to use its own

> resources (Company-owned generation or bilateral purchased power) when those native resources are the least cost power resource. In particular, the Day 2 market has facilitated the integration of wind energy resources in the regional dispatch much more efficiently than would be the case if NSP system operations had continued on a stand-alone basis.
>
> The Company continues to experience the benefits and efficiencies of the MISO Day 2 Market since its initial operation on April 2005 that enhanced NSP's ability to access low-cost power. On a qualitative [note], NSP['s] experience with the regional generation dispatch market operated by MISO shows benefits related to integration of wind generation resources in the regional economic dispatch. Absent of the MISO provided access to generation on a large regional basis, NSP would experience more disruptive local dispatch requirements, thereby increasing costs for our customers.

G. CONCLUSIONS REGARDING MISO DAY 1

Overall the Department concludes that the Companies' responses have complied generally with all of the AAA MISO Day 1 compliance reporting requirements. The Department expects utilities to continue to work hard to mitigate costs or the effects of changes by MISO or FERC that could negatively impact Minnesota retail customers. Utilities are required to continue to show benefits of MISO Day 1 in the context of their rate cases before receiving cost recovery of Schedule 10 costs.

The Department recommends that the Commission continue to require utilities to provide in the initial filing of all future electric AAA reports the Minnesota-jurisdictional Schedule 10 costs together with the allocation factor used and support for why the allocator is reasonable. Additionally, the Department recommends that the Commission continue to require utilities to provide information to support MISO Schedule 10 cost increases of five percent or higher over the prior year costs, including explanation of benefits received by customers for these added costs. This additional information would expedite the Department's review of MISO Day 1 costs in future electric AAA filings.

VIII. EFFECTS OF MISO DAY 2 ON MINNESOTA RATEPAYERS

A. BACKGROUND ON MISO DAY 2

This AAA report is based on eight full years of data under the MISO Day 2 energy market. Due to the significance of the MISO Day 2 markets on Minnesota ratepayers, the DOC dedicates this section to discussing the effects of this market on the way utilities procure energy and the way these costs are reflected in rates.

MISO's Day 2 energy market[51] both did and did not change the way utilities provide service to customers. On one hand, as noted by the Commission in its December 20, 2006 Order

[51] See the Open Access Transmission and Energy Markets Tariff (TEMT) in *Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 101,163 (2004).

Establishing Accounting Treatment for MISO Day 2 Costs (Docket Nos. E002/M-04-1970, E015/M-05-277, E017/M-05-284, and E001/M-05-406)), MISO's tariff re-characterized the way utilities provide electricity for the customers they are obligated to serve (native load customers[52]), including retail customers. Traditionally the utilities generated most of the electricity needed to serve their customers, and bought or sold any surplus or deficit from or to neighboring utilities. In contrast, MISO's tariff describes virtually all electric generation as a sale of electricity into a wholesale market, and describes the provision of electric service as entailing a purchase of power back from the market. On the other hand, the Commission required utilities to continue to use the lowest cost resources to serve customers, so this fundamental aspect of service did not change. Moreover, the Commission required a significant amount of oversight of the activity of utilities in the MISO Day 2 market. This oversight has included investigations, reports and various efforts to ascertain whether the utilities are, in practice, acting in the best interests of their customers in the Day 2 market. The following discusses more of the development of MISO Day 2.

On April 1, 2005, MISO began operation of the Day 2 Market, pursuant to its Transmission Energy Market Tariff (TEMT). In technical terms, MISO initiated regional security constrained economic dispatch with day-ahead and real-time energy markets (described below). The goal is to dispatch generation resources in the most efficient manner in the region, given transmission constraints. Under the Day 2 tariffs, all MISO participants that own or operate generation are required to submit offers for their generation resources (either owned generation or purchases) that are "Network Resources" of the market participant. At the same time, each MISO load serving entity (LSE) participant must bid their load requirements into the market. (Since utilities are market participants with generation and are also LSEs, utilities participate with both bids and offers.) After receiving the generation offers and load bids, MISO determines the optimal supply of resources that reflects delivery constraints on the transmission grid. MISO "clears" both the day-ahead and real-time markets over its entire footprint, based on participants' bids and offers and the limitations of the transmission system, with the optimized cost of supply.

The Commission issued the following three Orders addressing the utilities' petitions for cost recovery of MISO Day 2 costs.

First, because the Commission had not yet had sufficient opportunity to evaluate the parties' arguments, on April 7, 2005, the Commission provided temporary relief by permitting the parties to recover Day 2 costs through the FCA on an interim basis subject to refund.[53]

Second, in its December 21, 2005 Order, after further analysis, the Commission concluded that only certain costs should be recovered through the FCA. In particular, the Commission concluded that the costs of administering the MISO Day 2 Market listed in Schedule 16 and 17 were insufficiently related to energy or the types of costs previously recovered through the FCA to warrant FCA recovery. The Commission ordered the utilities to refund the balance to ratepayers.[54]

In addition the Commission established reporting requirements and accounting procedures to address the new regulatory dynamics created by MISO's Day 2 Market. In an effort to

[52] TEMT §1.208 (issued May 27, 2005).
[53] Order Authorizing Interim Accounting for MISO Day 2 Costs, Subject to Refund with Interest (April 7, 2005).
[54] Order Establishing Second Interim Accounting for MISO Day 2 Costs, Providing for Refunds, and Initiating Investigation (December 21, 2005 Order).

bring clarity to traditional utility operations, for example, the Commission directed the petitioning utilities to use "net accounting" for Day 2 costs, whereby both the proceeds of the "sale" and the costs of the "purchase" would be recorded in the same account. Because these two conceptual transactions would tend to cancel each other, the utility's records would reflect the net, or actual, cost or revenue from the operations. Finally, the Commission proposed an investigation into the best method for assuring low-cost electricity in Minnesota.[55] These basic principles are still in place.

Third, on reconsideration, Commission granted all parties additional time in which to address the requirement that utilities immediately implement a refund to their customers. By Order dated February 24, 2006, the Commission suspended the immediate refund obligation and restored the utilities' authorization to continue recovering all MISO Day 2 costs through the fuel clause. While this recovery remained as interim, subject to refund, the Commission also granted the utilities authority to implement deferred accounting for any costs that the Commission would later determine should not be recovered through the FCA. Utilities could continue deferring these costs until roughly March 1, 2009, without interest; thereafter the accrual would stop and the accrued balance would be written off gradually without rate recovery (amortized) through roughly March 1, 2012, unless the utility received Commission authority to recover the balance through base rates. The ultimate issue of whether and how MISO Day 2 costs should be recovered on a permanent basis was deferred to allow opportunity for additional analysis.[56]

On June 22, 2006, the parties filed the Joint Report and Recommendation Regarding MISO Day 2 Cost Recovery (Joint Report) with the Commission.[57] The Joint Report was supplemented by the comments filed on November 6, 2006. In brief, the Joint Report recommended that the Commission authorize utilities to recover most Day 2 costs via their fuel clauses. In support of the proposal, the utilities agreed to make certain commitments, described further below.

On December 20, 2006, the Commission issued its Order approving MISO Day 2 costs through the FCA, except for Schedule 16 and 17 costs. Schedule 16 and 17 costs were determined to be base rate costs recoverable in the context of a rate case, not energy costs recoverable through the FCA. The Commission's Order addressed conditions for virtual transactions, accounting practices, customer protections, wholesale revenues, and investigation by the Commission to ensure low-cost electricity in Minnesota. Finally, the Commission's Order required utilities to provide to the DOC several additional reporting requirements in their monthly FCA reports and AAA reports (ordering paragraph 7).

The DOC's analysis below is a limited review of MISO Day 2 overall charges, review of specific MISO Day 2 charges based on a fluctuation analysis, review of related allocations to customers, and review of asset-based margin sharing.

B. OVERALL EFFECTS OF MISO DAY 2 MARKET ON UTILITIES AND THEIR CUSTOMERS

According to MISO's tariff, the Day 2 Market encompasses both the "Day-Ahead Market" and the "Real-Time Market." To participate in the Day-Ahead Market, utilities forecast

[55] December 21, 2005 Order at Ordering Paragraph 10.
[56] Order on Reconsideration Suspending Refund, Granting Deferred Accounting and Requiring Filings at 7-8.
[57] The Joint Report reflected the views of all parties except for what is now known as the Office of Attorney General, Anti-Trust and Utilities Division.

customers' demand for electricity the next day, including the magnitude and geographical location of the demand. The utilities also designate the generators (network resources) they will make available to meet the total system's needs, and the terms under which each generator would provide electricity to the market if selected (dispatched). MISO then creates a least-cost plan to match supply with demand, consistent with the constraints of the generators and the transmission grid. The following day – the Real-Time Market – MISO implements its plans, adjusted to accommodate changes arising from, for example, unanticipated hot weather or a mechanical failure at a power plant.

In theory, the Day 2 Market enables MISO to dispatch generators with lower operating costs to meet the aggregate demand of all customers without regard to which utility owns a given generator or transmission line, or which utility has an obligation to serve a given customer. This process determines the marginal price of electricity – that is, the price of generating the last unit of power required to meet the combined needs of all customers, when all lower cost sources of power are already in use.

Sometimes MISO will be unable to use the system's lowest-cost generators because doing so would require moving electricity through a transmission line that is already fully in use (constrained). When such transmission constraints arise, MISO selects a substitute generator connected to transmission lines with available capacity, even though the substitute may be more expensive to operate. As a result, the marginal price of electricity is not uniform throughout the grid, but varies by location. This fact gives rise to the term "locational marginal price" (LMP), for electricity at each location on the transmission grid. As noted in the past FYE2007 and FYE2008 AAA filings, it has become evident that generation outages can have a significant effect on LMPs in the Day 2 market.

The DOC discusses our review and audit of MISO Day 2 charges in the next section, including recommendations regarding overall cost review and allocation of MISO Day 2 charges between retail and wholesale customers.

C. OVERALL REVIEW OF MISO DAY 2 CHARGES

This section discusses our overall review of MISO Day 2 charges and allocations between retail customers and the wholesale sector for the following areas:

- Day-Ahead and Real-Time Energy;
- Congestion Costs and Financial Transmission Rights (FTRs);
- Energy Losses;
- Virtual Energy/Non-Asset Based Transactions;
- Revenue Sufficiency Guarantee (RSG) Costs and Make Whole Payments;
- Revenue Neutrality Uplift (RNU) Charges;
- Auction Revenue Rights (ARR); and
- Grandfathered Charges.

The DOC's audit of MISO Day 2 charges started with the "MISO Day 2 Spreadsheet of Charges" as originally developed in the MISO Day 2 stakeholder process and as ordered by the Commission in its Final MISO Day 2 Order, Ordering Paragraph 7, part g. This MISO Day 2 spreadsheet of charges and additional support for MISO Day 2 net cost allocations, especially between retail and wholesale, was updated in the Commission's February 6, 2008 Order for the 2006 AAA, in Ordering Paragraphs 21 to 24.

1. Review of Xcel Electric's MISO Day 2 Charges

Xcel Electric allocates its MISO Day 2 charges across three categories including retail, asset-based wholesale/intersystem, and non-asset-based wholesale/intersystem. The Company's invoices from MISO are broken out into Xcel Electric's two asset owners: NSPP (generator asset owner) and NSPT (Xcel's trading owner which handles non-asset-based transactions). Since Xcel Electric has two asset owners set up with MISO, the MISO bill for a given month can be separated between NSPP and NSPT using the MISO daily settlements. A summary of MISO Day 2 charges assigned to the three categories is provided in Part J Section 5 on Schedule 7 page 13 of 13 of Xcel's Electric's FYE12 AAA Report. The Department notes that total amounts reflected on Part J Section 5 Schedule 7 are at the total Company level.

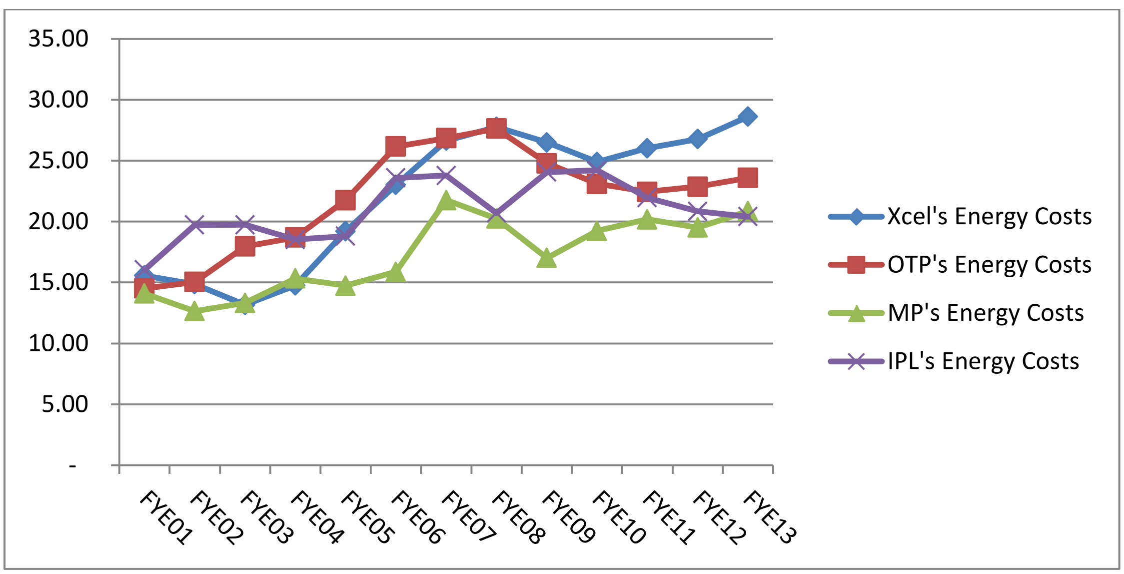
A summary of Xcel Electric's total MISO Day 2 charges assigned to retail customers on a total company basis for current and prior AAA reporting periods is provided below:

Table 4: Total MISO Day 2 Charges Assigned to Retail (in millions)

AAA Reporting Period	2008-2009	2009-2010	2010-2011	2011-2012	2012-2013
Net Costs	$226.2	$191.5	$195.9	$196.6	$200.5[58]

The Department notes that Xcel Electric's MISO Day 2 net costs assigned to retail are generally increasing some each year, with net costs being higher in 2008-2009 period when the MISO's locational marginal price (LMP) was higher. This trend mirrors the increased fuel costs utilities are generally experiencing:

Chart 1: Investor-Owned Utilities' Energy Costs ($/MWh)



The Department reviewed Xcel Electric's MISO Day 2 charges as reported in Part J, Sections 1 to 3 (narrative discussion) and Part J, Section 5, Schedules 1 through 7 for MISO Day 2 charges for FYE13 and continues to conclude they are reasonable, with the exception of the

[58] Source: Xcel's initial filing in Docket No. E999/AA-13-599, Part J, Section 5, Schedule 7, Page 13 of 13.

specific charge types described below, where the Department has asked for additional information.

First, the Department notes that total system Congestion and Financial Transmission Rights (FTR) Charges have increased significantly from $5,571,845[59] in FYE12 to $26,704,075[60] in FYE13, an increase of over $21 million and an increase of 379 percent in just one year. In addition, the Department notes that the percentage of Congestion and FTR Charges assigned to retail customers increased from 79.5% ($4,428,773[61]/$5,571,845[62]) in FYE12 to 91.6% ($24,474,234[63]/$26,704,075[64]) in FYE13. As a result, the Department asks the Company to explain in its reply comments the reason for this increase in total system Congestion and FTR Charges. In addition, the Department asks the Company to explain in reply comments why the percentage assigned to retail increased from 79.5 percent in FYE12 to 91.6 percent in FYE13.

Second, the Department notes that total system MISO RSG Charges (revenues) more than tripled from ($946,446)[65] in FYE12 to ($2,912,229)[66] in FYE13. As a result, the Department asks the Company to explain this increase in total system MISO RSG Charges (revenues) in its reply comments.

Third, the Department notes that total system MISO ARR revenues nearly tripled from ($2,782,494)[67] in FYE12 to ($7,774,930)[68] in FYE13. The Department asks the Company to explain this increase in total system MISO ARR revenues in its reply comments.

The Department also reviewed Xcel Electric's allocation of its MISO Day 2 charges across its retail, asset based wholesale/intersystem and non-asset based wholesale/intersystem. The Department described Xcel Electric's allocation methods in detail in the Department's *Review of the 2010-2011 Annual Automatic Adjustment Reports*.[69] The Department recommends that Xcel Electric explain, in reply comments, if any of the Company's allocation methods changed during the 2012-2013 reporting period. If so, the Department recommends that Xcel Electric explain, in reply comments, the nature of these changes, why changes in allocators are reasonable and superior to the prior allocator, and the effect these changes had on the charges assigned to various customer categories in the 2012-2013 AAA Report.

The Department recommendations that the Commission not accept Xcel Electric's MISO Day 2 reporting at this time until the Company has provided the required information in its reply comments.

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[59] Source: Xcel's initial filing in Docket No. E999/AA-12-757, Part J, Section 5, Schedule 7, Page 13 of 13.
[60] Source: Xcel's initial filing in Docket No. E999/AA-13-599, Part J, Section 5, Schedule 7, Page 13 of 13.
[61] Source: Xcel's initial filing in Docket No. E999/AA-12-757, Part J, Section 5, Schedule 7, Page 13 of 13.
[62] *Id.*
[63] Source: Xcel's initial filing in Docket No. E999/AA-13-599, Part J, Section 5, Schedule 7, Page 13 of 13.
[64] *Id.*
[65] Source: Xcel's initial filing in Docket No. E999/AA-12-757, Part J, Section 5, Schedule 7, Page 13 of 13.
[66] Source: Xcel's initial filing in Docket No. E999/AA-13-599, Part J, Section 5, Schedule 7, Page 13 of 13.
[67] Source: Xcel's initial filing in Docket No. E999/AA-12-757, Part J, Section 5, Schedule 7, Page 13 of 13.
[68] Source: Xcel's initial filing in Docket No. E999/AA-13-599, Part J, Section 5, Schedule 7, Page 13 of 13.
[69] The Department's *Review of the 2010-2011 Annual Automatic Adjustment Reports* was filed June 1, 2012 in Docket No. E999/AA-11-792.

2. Review of MP's MISO Day 2 Charges

The Department reviewed Minnesota Power's MISO Day 2 charges as reported in Attachment 9 to its FYE13 AAA report and, as described below, requests that MP provide additional information in reply comments. The Department also discusses several noteworthy aspects of MP's MISO Day 2 reporting.

During its review of MP's MISO Day 2 charges, the Department noted that MP's Day Ahead Asset Energy Charges were $8.2 million in November, 2012, but averaged only $3.6 million in the other eleven months of FYE13. In its response to Department Information Request No. 16, MP explained that this increase in Day Ahead Assets Energy Charges in November was a result of its three Taconite Harbor Energy units being taken offline following a coal dust explosion, which forced MP to rely on the Day Ahead Market to replace the lost generation. The Department notes that this forced outage gives an example how significant the cost increase of relying unexpectedly on the Day Ahead Market can be.

During its review, the Department also noted an increase in volatility in MP's Non-Excessive Energy charges during FYE13 relative to FYE11 and FYE12. Non-Excessive Energy charges occur when a unit does not produce the amount of energy in real time that it committed to produce in the Day Ahead market. In four months of FYE13, MP's Non-Excessive Energy charges were higher than in any single month during FYE11 and FYE12. In its response to Department Information Request No. 18, MP noted that the volatility was attributable to four months in FYE13: July 2012, November 2012, January 2013, and March 2013. MP explained that in July 2012, Boswell Energy Center (BEC) Units 3 and 4 had an unscheduled outage due to a lightning strike and was therefore unable to produce the energy in real time that it had committed to produce in the Day-Ahead market. In November 2012, output at MP's Bison and Oliver County wind farms was limited by both icing conditions and transmission constraints in North Dakota. Additionally, BEC Unit 4 experienced a forced outage due to a boiler tube leak. In January 2013, output from the Company's Bison wind farms was limited again due to icing conditions and transmission restrictions, and BEC Unit 3 experienced a forced outage due to a turbine extraction leak on the superheater outlet. Lastly, in March 2013, MP's Milton R. Young (Young 2) generating station experienced a forced outage due to boiler tube leaks.

During its review, the Department noted that MP's Day-Ahead Loss Charges in FYE13 averaged $1.5 million per month, compared to $1.1 million per month during FYE11 and FYE12. In its response to Information Request No. 19, MP explained that this apparent increase is the result of a change only in reporting, not a change in actual operations. Prior to 2012, losses on MP's direct current (DC) line were reported as an increase in load. Starting in 2012, losses on the DC line were reported as Day-Ahead Loss charges, which accounts for the observed increase.

The Department also noted during its review that MP's Day-Ahead Congestion charges in January 2013 were $2.7 million, but averaged only $0.5 million per month during the other eleven months of FYE13. In its response to Information Request No. 20, MP explained that a transmission constraint on the North Shore Loop created high prices until the constraint was relieved; however, MP provided no other information. The Department requests that MP describe in reply comments the nature of the transmission constraint (*i.e,* was there a transmission outage, higher-than-normal flows, etc.) and how it was relieved.

The Department also reviewed Minnesota Power's allocation of its MISO charges across its various customer categories. The Department described Minnesota Power's allocation methods in detail in the Department's *Review of the 2010-2011 Annual Automatic Adjustment Reports*.[70] Because those allocation methods have not changed, the Department will describe them only briefly in this report.

Minnesota Power allocates energy-related charges (including several MISO Day 2 charges) using an algorithm which assigns highest-cost generation or purchases to non-FCA customer categories, theoretically leaving lowest-cost generation or purchases as the responsibility of Minnesota Power's FCA customers (retail and municipal customers). Virtual energy charges are directly assigned to the FCA customer categories. All other non-energy MISO costs are allocated on a per MWh basis. The Department concludes that these allocation methods are generally reasonable, but cautions that it did not attempt to audit or verify the result of Minnesota Power's algorithm for allocating energy costs.

The Department recommends that the Commission not accept MP's MISO Day 2 reporting until MP provides in reply comments the additional information requested regarding its January 2013 Day-Ahead Congestion Charges.

3. Review of OTP's MISO Day 2 Charges

OTP allocates its MISO Day 2 charges across three categories including retail, asset-based wholesale, and non-asset-based wholesale. OTP also refers to these categories as its "resource," "marketing" (OTPW) and "dealing" (OTPD) portfolios. OTP's MISO Day 2 charges for retail and asset-based wholesale are billed under OTPW settlement statements. MISO Day 2 charges for non-asset-based wholesale are billed separately under OTPD settlement statements. A summary of MISO Day 2 charges assigned to the three categories is provided in Attachment K of OTP's 2012-2013 AAA Report. The Department notes that amounts totals reflected in Attachment K are at the total Company level and not the Minnesota jurisdictional level.

A summary of OTP's total MISO Day 2 charges assigned to retail customers for current and prior AAA reporting periods is provided below:

Table 5: Total MISO Day 2 Charges Assigned to Retail

AAA Reporting Period	2008-2009	2009-2010	2010-2011	2011-2012	2012-2013
Revenues	$253.9 million	$175.1 million	$115.1 million	$87.0 million	$113.8 million
Costs	$276.3 million	$191.6 million	$131.2 million	$115.0 million	$145.2 million
Net Costs	$22.4 million	$16.5 million	$16.1 million	$28.0 million	$31.4 million

The Department Reviewed OTP's MISO Day 2 charges as reported in Attachment K to its 2012-2013 AAA Report. The Department recommends that OTP explain, in reply comments, why the total 2012-2013 MISO Day 2 net charges increased from $28.0 million in 2011-2012 to $31.4 million in 2012-2013, or a $3.4 million increase.

OTP's Day Ahead Energy Losses (DA Loss Amt) totaled $667,718.57 in April, 2013. This amount is significantly higher than the costs charged in other months during the 2012-2013 AAA reporting period. The Department recommends that OTP explain, in reply comments, why the Company incurred such large Day Ahead Energy Losses (DA Loss Amt) in April, 2013 and why these costs are appropriately assigned to retail customers.

[70] The Department's *Review of the 2010-2011 Annual Automatic Adjustment Reports* was filed June 1, 2012 in Docket No. E999/AA-11-792.

In addition, OTP's total for Day Ahead and Real Time Energy Loss from July 2012 to June 2013 increased by approximately $3.4 million with only an increase in revenues of approximately $1 million as compared to the previous year's filing. The majority of the increased costs appear to be related to increase Day Ahead Losses (DA Loss Amt). The Department recommends that OTP explain, in reply comments, why the Company incurred increased Day Ahead and Real time Energy Losses in the July 2012 to June 2013 as compared to the previous year, and why these costs are appropriately assigned to retail customers.

OTP's Day Ahead Congestion (DA FBT Congestion Amt) costs totaled $841,757.53 in August, 2013. This amount is significantly higher than the costs charged to other months during the 2012-2013 AAA reporting period. The Department recommends that OTP explain, in reply comments, why the Company incurred such large Day Ahead Congestion (DA FBT Congestion Amt) costs in August, 2013 and why these costs are appropriately assigned to retail customers.

OTP's RSG and Make Whole Payments costs totaled $251,163.27 in May 2013. This amount is significantly higher than the costs charged to other months during the 2012-2013 AAA reporting period. The Department recommends that OTP explain, in reply comments, why the Company incurred such large RSG and Make Whole Payments costs in May, 2013 and why these costs are appropriately assigned to retail customers.

The Department also reviewed OTP's allocation of its MISO Day 2 charges across its various customer categories. The Department described OTP's allocation methods in detail in the Department's *Review of the 2010-2011 Annual Automatic Adjustment Reports*.[71] In the reply comments in the 2011-2012 *Annual Automatic Adjustment Reports*[72] the Company stated that there were no changes in its allocation method since the previous report. The Department recommends that OTP explain, in reply comments, if any of the Company's allocation methods changed during the 2012-2013 reporting period. If so, the Department recommends that OTP explain, in reply comments, the nature of these changes and the effect these changes have had on the charges assigned to various customer categories in the 2012-2013 AAA Report.

The Department recommends that the Commission not accept OTP's MISO Day 2 reporting at this time until the Company has provided the required information in its reply comments and the Department is able to review OTP's information.

4. *Review of IPL's MISO Day 2 Charges*

Interstate Electric is unique in its treatment of MISO Day 2 costs compared to other Minnesota utilities, in that it does not allocate MISO Day 2 costs between retail customers and the wholesale sector, as all energy costs, all energy revenues, and all MWhs are included in its FCA. Interstate Electric uses the net of all costs and revenues and divides this amount by all MWhs. The DOC considers this approach to be an all-in method, which was approved in Interstate Electric's prior rate cases. A benefit of this approach is simplicity, and the fact that there are no concerns about allocation proportions of MISO Day

[71] The Department's *Review of the 2010-2011 Annual Automatic Adjustment Reports* was filed June 1, 2012 in Docket No. E999/AA-11-792.
[72] The Company's reply comments for the *2011-2012 Annual Automatic Adjustment Reports* was filed September 20, 2013 in Docket No. E999/AA-12-757.

2 costs between retail customers and the wholesale sector. Conversely, as part of this all-in process, efforts cannot be made to assign the lowest cost resources to retail customers.

As shown on Attachment C, page 13 of 13 for FYE11, FYE12, and FYE13 AAA reports, the Department noted a decrease in Interstate Electric's MISO Day 2 charges, which includes asset based wholesale in addition to retail. Below is a table showing Net Costs assigned to retail customers since 2010; the Department notes that the amount of retail costs has been declining for the past several AAA reporting periods, while retail revenues have been increasing, resulting in a reduction of retail net costs:

Table 6: Historical MISO Day 2 Net Costs Assigned to Retail Customers

Period	Retail Costs	Retail Revenue	Retail Net Costs
2010-2011	$99,941,288.70	$20,127,899.82	$79,813,388.88
2011-2012	$92,291,999.68	$22,483,756.56	$69,808,243.12
2012-2013	$66,914,361.67	$25,260,345.97	$41,654,015.70

In attempting to isolate the cause of the sudden drop in retail costs in 2012-2013, the Department identified Congestion and Financial Transmission Rights (FTRs) as the main reason for the cost reduction. Interstate Electric responded to an information request by the Department and explained that the drivers of the change were the increased revenue gained from FTR Hourly Allocation charges and the FTR Transaction charges which decreased overall costs flowing through the Fuel Cost Adjustment.[73] The increased congestion in the Interstate Electric control area has raised the value of day-ahead FTRs, and concurrently decreased overall MISO charges.

Based on a limited review, Interstate Electric's allocation of costs appears to be reasonable for the FYE13 reporting period and therefore the Department recommends that the Commission accept Interstate Electric's MISO Day 2 reporting.

D. ASSET BASED MARGIN OR WHOLESALE REVENUE REVIEW

1. Xcel Electric

Since the Department reviewed Xcel's asset based margins in its current rate case (Docket E002/GR-13-868), the Department performed a cursory review of Xcel Electric's asset based margins in the FYE13 AAA, to ensure give back of asset-based margins to ratepayers via the FCA. Based on our review, the Department concludes that Xcel's asset based margins appear to be reasonable.

2. MP

The table below summarizes MP's actual wholesale asset-based margins over the period 2009 through 2013, and compares those margins to the revenue credit built into MP's base rates each year. As shown, the sum of MP's actual margins over the five-year period ($181.9 million) is roughly equal to the total revenue credit ($181.1 million) over the same period, differing by only 0.4 percent. However, on an annual basis, the difference between MP's actual margins and the revenue credit built into base rates fluctuates significantly, ranging from a $23.5 million benefit to shareholders in 2009 to an $8.2 million dollar loss

[73] MN DOC Information Request No. 4 issued July 3, 2014, response received July 13, 2014.

for shareholders in 2012. The Department will continue to monitor MP's wholesale margins in future AAA filings.

Table 7:
Minnesota Power's
Wholesale Asset-Based Margins[74]

Minnesota Power
Wholesale Asset-Based Margins

Calendar Year	Actual Margin	Revenue Credit Built into Base Rates	Shareholders Benefit/(Cost)	Percent Difference
[a]	[b]	[c]	[d]=[b]-[c]	[e]=[d]/[c]
2009	$53.8	$30.3	$23.5	77.6%
2010	$33.9	$37.7	($3.8)	-10.1%
2011	$31.1	$37.7	($6.6)	-17.5%
2012	$29.5	$37.7	($8.2)	-21.8%
2013	$33.6	$37.7	($4.1)	-11.0%
Total	$181.9	$181.1	$0.8	0.4%

3. OTP

The Department reviewed OTP's asset-based margins to ensure give back to the ratepayers via the FCA. Based on our review, the Department concludes that OTP's asset based margins appear to be reasonable.

4. IPL

Due to IPL's all-in approach where all revenues and costs for retail and wholesale customers are included in their FCA and divided by total kWh, asset based margins are embedded in their total net fuel costs.

[74] Sources: 2009 and 2010 Actuals: MP Response to DOC Information Request No. 58 in FYE09 and FYE10 AAA Proceeding; 2011 Actual: MP's response to DOC Information Request No. 1 part (E) in Docket No. E015/M-11-1264; 2012 Actual: MP Response to DOC Information Request No. 21 in Docket No. E999/AA-12-757; 2013 Actual: MP Response to DOC Information Request No. 10 in the instant proceeding; 2009 Revenue Credit in Base Rates: May 4, 2009 Order in Docket No. E015/GR-08-415, page 17; 2010-2013 Revenue Credit in Base Rates: November 2, 2010 Order in Docket E015/GR-09-1151.

E. DOC INVOLVEMENT IN MISO PROCESSES

The DOC actively participates in Organization of MISO States (OMS) Workgroups which correspond with MISO workgroups and subcommittees. This approach has been a useful process for providing joint filings with FERC on the more significant MISO filings. The OMS has also helped the DOC be more proactive in its interaction with MISO. The DOC continues to attend or listen to MISO Advisory Meetings, Annual Stakeholder and Sector Meetings with MISO, Resource Adequacy Workgroup and Supply Adequacy Workgroup (RAWG/SAWG) Meetings, Midwest Transmission Expansion Plan (MTEP) Meetings, Demand Response Meetings and other MISO meetings to gain better understanding of MISO proposals prior to implementation.

The DOC has also found the Minnesota Commission's MISO Quarterly Meetings to be helpful to share information and ask questions of the Utilities and MISO experts. The DOC greatly appreciates the efforts by the Commission to bring all of the parties together and to facilitate the discussions. The Department also appreciates the participation of all entities in this process. In particular, the DOC commends the Commission for focusing the discussions, and thanks the utilities and MISO for their significant efforts, discussions, and willingness to solve problems as they arise.

F. SUMMARY OF CONCLUSIONS REGARDING MISO DAY 2 COSTS AND REVENUES

The DOC concludes that the review of MISO Day 2 charges and allocations are complex. Due to the volume of information related to these transactions, and the less-than-transparent nature of MISO billings in allocating between retail and asset-based wholesale transactions and some of the utilities' fuel clause ratemaking processes.

Overall, utilities have improved the quality of their explanations regarding fluctuations and/or changes in MISO Day 2 overall costs and charges. As noted above, the DOC still has some remaining questions about overall MISO charges and cost allocations that we have asked utilities to respond to in their reply comments. Once this information is provided, the DOC will review the additional information and make our final recommendation to the Commission.

The DOC intends to continue to audit the MISO Day 2 charge and allocations between retail and wholesale customers. The DOC includes a list of all its recommendations formulated at this time, including recommendations for this MISO Day 2 section, below in the recommendations section.

VIII. ANCILLARY SERVICES MARKET (ASM)

A. BACKGROUND

Utilities must hold enough capacity to meet their load and provide reliable service to comply with North American Electric Reliability Corporation (NERC) reliability standards. The reliability component includes ancillary services. Ancillary services ensure that there is sufficient generation to match loads on the transmission system instantaneously to preserve service reliability.

These ancillary capabilities are as follows:

- Regulation service: having generation operating and able to change their MW output (up or down) to respond to changes in load on a second-by-second basis;
- Spinning Reserve service: having generation on line (spinning) at reduced output, so that it can immediately provide replacement power in the event of an unscheduled outage at another generation unit;
- Supplemental Reserve service: having generation readily available off-line and capable of starting and beginning to generate within ten (10) minutes to respond to an unscheduled outage at another generation unit; and
- Energy Imbalance service: providing energy between entities, such as between a utility and a municipal load-serving entity (which is typically a wholesale customer of the utility), to account for the difference between the amount scheduled during a period (such as an hour) and the amount actually delivered (which may be more or less than the amount scheduled). Energy Imbalance service could be settled either by an "in kind" exchange of energy in a later period, or financially.

MISO's Ancillary Services Market (ASM) began operations on January 6, 2009. The 12 ASM charges are as follows:

Six procurement charges:	1) Day-Ahead Regulation; 2) Day-Ahead Spinning Reserve Charge; 3) Day-Ahead Supplemental Reserve; 4) Real-Time Regulation; 5) Real-Time Spinning Reserve; 6) Real-Time Supplemental Reserve;
One Resource Energy charge:	1) Net Regulation Adjustment;
Three Cost Distribution charges:	1) Regulation; 2) Spinning Reserve Charge; and 3) Supplemental Reserve; and
Two penalty charges:	1) Regulation Penalty Amount; and 2) Contingency Reserve Development Failure Penalty.

Prior to the start of MISO's ASM, ancillary services were procured in the MISO footprint by each utility through bilateral contracts via Balancing Authorities to the MISO as the Provider of Last Resort. On a day-ahead basis, individual Balancing Authorities identified how resources in their Balancing Authority area (formerly referred to as a "control area") would be able to provide the required amounts of ancillary service, which resulted in capacity on native generation resources being held back to provide services of regulation, spinning reserve and supplemental reserve. On a real-time basis, Balancing Authorities dispatched their resources on a second-by-second basis to meet system reliability requirements. If the utility was unable to meet the energy requirements needed to serve their load and provide the necessary ancillary services, they were required by NERC reliability standards to purchase additional energy while they held back capacity to meet reliability needs.

The Commission's Order dated August 23, 2010 in Docket No. M-08-528 (Commission's August 23, 2010 ASM Order) approved Xcel Electric's, MP's, and Interstate Electric's ASM accounting and recovery via the FCA and required reporting requirements as follows (the DOC notes that OTP's ASM was approved via their rate case in GR-10-239):

1. The Commission accepts the quarterly reports filed by the three utilities under the March 17, 2009 order in this case.

2. The Commission finds that the record demonstrates overall benefits from the three utilities' participation in the MISO ancillary services market and that the record supports the continued use of the Fuel Clause Adjustment to pass through the costs and revenues associated with that participation. The three utilities are authorized to continue using the Fuel Clause Adjustment to pass through the costs and revenues associated with their participation in the MISO ancillary services market.

3. With the exception of Contingency Reserve Deployment Failure Charges and Excess/Deficient Energy Charges, the Commission removes the "subject to refund" provisions of the March 17, 2009 order for both past and future ancillary services market costs passed through the Fuel Clause Adjustment.

4. All costs and revenues associated with the utilities' participation in the MISO ancillary services market remain subject to the normal review, approval, and recovery procedures that apply to costs and revenues passed through the Fuel Clause Adjustment.

5. The three utilities shall include costs and revenues from their participation in the MISO ancillary services market in future automatic adjustment reports filed under Minn. Rules, parts 7825.2390 *et seq.*, including the annual filing required there under. They shall include costs/revenues through June 30, 2010 in the 2011 annual filings, which are due in September 2010; they shall include costs/revenues beginning July 1, 2010 in the 2012 annual filings, which are due in September 2011.

6. The three utilities shall continue to monitor and report all negative benefits (costs) of participation in the MISO ancillary services market and shall work with MISO to ensure that negative benefits occur, if at all, for limited periods of time and with minimal financial impact.

7. The three utilities shall base the formatting of their reports on costs and revenues associated with participation in the MISO ancillary services market on the format used by Xcel and Minnesota Power in this docket.

8. In their annual summaries on the 12 MISO ancillary services charges the utilities shall use a format similar to that used by Minnesota Power in its Attachment 1 to its February 5, 2010 filing (4th quarter report) and shall work with the OES [Department] to develop a format that is acceptable.

9. In reporting daily ancillary services market activity and overall net savings created by participation in the ancillary services market, utilities shall use a format similar to that used by Xcel in Attachment A to its February 5, 2010 filing and shall work with the OES [Department] to develop a format that is acceptable.

10. The utilities' written narratives on the benefits of the ancillary services market and the market's impact on their systems shall be formatted consistent with Xcel's and Minnesota Power's 4th quarter report in this docket.

11. The utilities shall file detailed and specific explanations for all Contingency Reserve Deployment Failure and Excess/Deficient Energy Charges incurred, including an explanation as to why they should be recovered and what actions the utility took to minimize these charges.

12. The utilities shall clearly identify and separately list in their automatic adjustment reports all ancillary services market values included in those reports and/or passed through the Fuel Clause Adjustment.

The Excessive/Deficient Energy Deployment Charge amount represents the charge to the generator that was not able to maintain actual generator output to within a tolerance band around the set point. During the hours where a generator was unable to meet this requirement, MISO assesses a charge equal to any Day-Ahead or Real-Time payments to the generator for carrying regulation reserve plus the generator's pro rata share of costs to procure regulation from all resources within MISO.

The Contingency Reserve Deployment Failure Charge represents the charge incurred by generation or demand response resources that fail to deploy contingency reserves at or above the contingency reserve deployment instruction. This charge is assessed if a unit that is selected to provide spinning or supplemental reserves during a specific hour does not perform, and MISO must then deploy another resource.

B. XCEL ELECTRIC

Xcel Electric provided its ASM review in its FYE13 AAA filing in Part J, Section 5, Schedules 8 to 13 and in Part J, Section 6, Schedules 1 to 3 as required by the Commission's August 23, 2010 Order in Docket M-08-528. Specifically, Xcel Electric stated the following regarding overall ASM market performance:[75]

[75] Source: Xcel's initial filing in Docket No. E999/AA-13-599, Part J, Section 6, Page 1 of 6.

> During the 2012-2013 AAA Period, MISO continued to operate the electric system reliably and has exceeded compliance thresholds for all North American Electric Reliability Corporation (NERC) reliability standards to which they are subject. The MISO Independent Market Monitor, which is tasked with monitoring both the behavior of Market Participants and the operation of the market, noted in its 2012 State of the Market Report that "The MISO energy and ancillary service markets generally performed competitively in 2012." The Market Monitor also noted 2012 prices were 14% lower than 2011 due to lower fuel prices. (Footnotes omitted)

The Department notes that Xcel's total system ASM costs have increased significantly from $10,665,160[76] in FYE12 to $22,631,901[77] for FYE13, more than doubling the cost over one year. As a result, the Department recommends that Xcel explain this increase in total system ASM costs in its reply comments.

Xcel Electric also provided a calculation of its net savings related to ASM for FYE13.[78] The Company showed net ASM savings of $17.6 million for the total NSP system and $13.2 million for the Minnesota Jurisdiction. Xcel stated that these net savings are associated with optimizing the generation units that are carrying ancillary services across the entire MISO footprint. In addition, Xcel stated that its net savings calculation did not include any additional benefits that have accrued to ratepayers for the reduction in regional regulatory reserve requirements.

Xcel provided its monthly Excessive/Deficient Energy Deployment Charges (EDEDC) in Part J, Section 6 of its filing. The Department notes that Xcel's total system EDEDC has increased substantially from $102,868[79] in FYE12 to $979,562[80] in FYE13; while this cost is relatively small, the nearly 10-fold increase in one year is concerning. Regarding this increase, Xcel stated that:

> In December 2012, MISO implemented changes in accordance with FERC Order 755 by adding a regulation mileage product to financially compensate for actual generator movement. An increase in [excessive deficient energy deployment charges] EDEDC charged to NSP began in January 2013, which is attributed to the overall rate increase associated with the addition of the mileage component and higher LMPs. This increase was offset by an increase in the revenues received by NSP for Regulation. When comparing the first 7 months in 2012 to 2013, the next expenses increased by less than $150,000. Though EDEDC increased year over year, NSP has also seen a similar increase in the Regulation revenues. While some increase in total EDEDC charges was inevitable due to

[76] Source: Xcel's initial filing in Docket No. E999/AA-12-757, Part J, Section 5, Schedule 13, Page 13 of 13.
[77] Source: Xcel's initial filing in Docket No. E999/AA-13-599, Part J, Section 5, Schedule 13, Page 13 of 13.
[78] Source: Xcel's initial filing in Docket No. E999/AA-13-599, Part J, Section 6, Schedule 1, Page 1 of 6.
[79] Source: Xcel's initial filing in Docket No. E999/AA-12-757, Part J, Section 6, Schedule 2, Page 1 of 1; sum of all months for FYE12.
[80] Source: Xcel's initial filing in Docket No. E999/AA-13-599, Part J, Section 6, Schedule 2, Page 1 of 1; sum of all months for FYE13.

> this change, NSP has identified that Riverside, Sherco 1, and Sherco 2 received a disproportionate share of these charges. For Riverside, the root cause was a change in the Distributed Control System (DCS) which was restricting the ramp of the plant relative to the ramp rate offered to the MISO market. The Riverside DCS restriction has since been corrected, but NSP continues to monitor the plant performance. For Sherco 1 & 2, no conclusions have been reached at the time of this report, but NSP is analyzing individual events to determine a root cause.

Given the significant year-over-year increase and the large EDEDC amounts assigned to Sherco units 1 and 2, the Department recommends that Xcel explain in reply comments whether it has reached any conclusions regarding the root cause for Sherco 1 and 2. In addition, the Department recommends that Xcel continue to work with MISO to mitigate these costs in the future.

Xcel provided its monthly Contingency Reserve Deployment Failure Charges (CRDFC) for FYE13 in Part J, Section 6, Schedule 3 of its filing. As shown therein, Xcel's CRDFC totaled $53,160[81] for FYE13, which amounts to a $45,761 increase over FYE12 CRDFC of $7,399.[82] Regarding its FYE13 CRDFC, Xcel stated that:

> The charges are the result of 2 days during the year when NSP resources failed to meet requested deployment volumes. NSP carries reserves on units with Automatic Generation Control (AGC) and units without AGC. For units without AGC, a phone call to the facility is required to deploy the reserves, adding to the time from receiving the signal and deployment. When deploying a large amount of reserves on many facilities, that action requires many more steps and time becomes critical. Additionally, MISO must meet Disturbance Control Standards within 15 minutes but does not always provide market participants the remaining time between the deployment signal and the end of the 15-minute timeframe to deploy reserves. Instead, MISO holds participants to a 10-minute response regardless if MISO has 15 minutes to meet the standard or less than 10 minutes.
>
> The charges were not the result of any improper action by the Company, but simply reflect the fact that generating units are sometimes not able to deliver every requested MW. The Company attempts to minimize these occurrences, as evidenced by the limited charges incurred over the reporting period. Had a similar situation occurred before the start of ASM, the Company would have been required to deploy reserves from another generator in its fleet, and would have

[81] Source: Xcel's initial filing in Docket No. E999/AA-13-599, Part J, Section 6, Schedule 3, Page 1 of 1; sum of all months for FYE13.
[82] Source: Xcel's initial filing in Docket No. E999/AA-12-757, Part J, Section 6, Schedule 3, Page 1 of 1; sum of all months for FYE12.

> incurred increased energy costs that were recovered in the FCA. Thus it is reasonable for the Company to recover these minor charges from MISO.
>
> The Company tests all resources capable of providing supplemental reserve response every two months to validate capability and readiness if called on by MISO during a contingency. If a resource fails to perform during a test, plant management will address the issue with any required maintenance to return the unit to reliable service. The offer to MISO for the unit to provide reserves will be adjusted accordingly to ensure the capabilities of the unit are not overstated during this time.
>
> In short, CRDFCs are prudently incurred for the same reasons described above regarding Excessive Deficient Energy Deployment charges. Generators are complicated mechanical machines whose performance varies based on many conditions. The benefits of making these units available to provide significant amounts of spinning and supplemental reserves to hedge the Company's cost to procure ancillary services more than offsets the cost of the extremely infrequent circumstances where the unit may not be able to provide 100% of the amount required. Also, Xcel Energy is working to modify the rules which evaluate failure to deploy so that this charge is only applied when a unit fails compared to its offered physical capability.

Based on the Company's explanation above, the Contingency Reserve Deployment Failure Charges appear to be reasonable at this time. However, the Department recommends that Xcel continue to work with MISO to mitigate these costs in the future.

The Department recommends that the Commission not accept Xcel Electric's ASM reporting until the Company has provided the information noted above in its reply comments.

C. MP

MP addresses ASM costs and benefits in Attachment 10 to its FYE13 AAA Report, which was submitted to the Commission on September 30, 2013 in a Supplemental Filing. MP reports a net cost of $74,441 in FYE13, compared to a net cost of $184,594 in FYE12. On page 3 of Attachment 10, MP stated that it supplied fewer MWh of Regulation, Spinning and Supplemental Reserves in FYE13 than it supplied in FYE12, which accounts for the increase in net costs. Attachment 10-B, which summarizes MWh of ASM products procured and supplied by MP, supports this assertion. Attachment 10-B reports that MP supplied 213,792 MWh of ASM products in FYE13, versus 320,376 MWh in FYE12, a decrease of 106,584 MWh. MP's procurement of each of the three ASM services in FYE13 was 532,507 MWh, only 12,041 MWh higher than in FYE12.

MP treats ASM charges and credits as non-energy costs and allocates them across customer categories on a per MWh basis.

The Department recommends that the Commission accept MP's ASM reporting.

D. OTP

In Section V, Attachment L its FYE13 AAA Report, OTP provided its ASM information as required by the Commission's August 23, 2010 Order in Docket M-08-528. Specifically, OTP noted that ASM market transition has been smooth from an operational standpoint. OTP noted there has been a positive economic benefit for OTP, as a result of maximizing capabilities of generating units, which has led to greater operational efficiency. OTP's Schedule 1 shows that OTP is a net seller of ASM products (Regulation, Spinning Reserve, and Supplemental Reserve). As a result, ASM provided net benefits of $282,691 to Minnesota ratepayers in 2012-2013. OTP allocates all ASM charges on a per MWh approach netting costs and benefits of the various charges.

The Department notes that ASM net benefits for OTP's Minnesota customers have increased significantly from $32,764 in 2011-2012 to $282,691 in 2012-2013. The Department recommends that the Commission accept OTP's ASM reporting.

E. INTERSTATE ELECTRIC

Included in Attachments D through F of its FYE13 AAA filing, Interstate Electric provided its ASM information as required by the Commission.[83] Pages 1 through 8 in Attachment D detail the Regulation, Spinning Reserve, Supplemental Reserve, and Other Charges and resulting subtotals for all four quarters included in FYE13. The DOC notes that for Regulation and Supplemental Reserves in FYE13, Interstate Electric was a net purchaser for Regulation and Supplemental Reserve, and a net seller for Spinning Reserve, as Table 3 below illustrates. The subtotal for Other Charges in FYE13 was $538,708.58.[84] This amount compares to $70,334 in FYE12 and $73,995 reported for FYE11 AAA filing.[85]

Table 8: MISO ASM Charges for Interstate Electric FYE13

Charge Type	Q1	Q2	Q3	Q4	FYE13 Total
Regulation	$105,680.27	$28,017.84	$(72,852.77)	$(110,736.99)	$(49,891.65)
Spinning Reserve	$6,492.46	$95,562.00	$62,587.64	$43,774.48	$208,416.58
Supplemental Reserve	$(52,209.97)	$(48,559.16)	$19,206.44	$1,779.41	$(79,783.28)
Other	$43,420.76	$44,775.17	$191,270.27	$259,242.38	$538,708.58

Similar to Xcel, the reason for the significant increase to IPL's Other Charges amount in FYE13 was an increase in the Excessive/Deficient Energy Deployment Charge Amount (EDEDC). In Attachment H, Interstate Electric explained that the EDEDC charges began to increase significantly upon a tariff change by MISO that implemented Regulation Mileage in December of 2012.[86] These new requirements base payments on the accuracy of a unit's

[83] Commission's August 23, 2010 Order in Docket No. M-08-528.
[84] IPL 2013 Annual Filing Attachment D, "Other Charge Subtotal" for all four quarters in the reporting period.
[85] IPL 2011 and 2012 Annual Filings, Attachment D, "Other Charge Subtotal" for all quarters in the reporting period.
[86] IPL 2013 Annual Filing Exhibit H, Page 21

response to a call for Regulation by MISO. Units that were able to provide Regulation more efficiently than others were rewarded, examples of which included flywheels, which are explicitly designed to provide Regulation. Interstate Electric does not own any flywheels, and still offers and is awarded to provide Regulation. Interstate Electric's assets are not suited to meet the Regulation Mileage criteria and they have therefore been assessed EDEDC charges. As stated in Exhibit H, Interstate Electric's EDEDC Charges have average $65,722.20 per month since the tariff change has gone into effect. Interstate Electric stated that:

> IPL and other MISO generator owners still need to offer their units in for Regulation. There are no flywheel or any other types of units within the MISO market that are extant that could provide the Regulation that is currently offered by more traditional units. If IPL and other generator owners did not offer in Regulation, system reliability would not be sustainable. Therefore, the Commission should allow recovery of the EDE[D]C charges.

In Attachment F, Interstate Electric reported seven instances of Contingency Reserve Deployment Failure (CRDF) penalties, totaling $17,255.85 incurred during this reporting period. This amount is an increase of approximately $2,500 from FYE12, and $14,500 from FYE11. Interstate Electric stated that:

> Almost all the charges ($16,609.97) are related to Hour Ending 14:00 on July 5, 2012. The weather was extremely hot. Because of the heat, four smaller combustion turbines were not able to achieve their offered capacity. Although the total shortfall for the four units combined was only 15.8 MW, Real Time Locational Marginal Prices at the four locations spiked, ranging from $991.67 to $1,062.08 per megawatt hour. The other three instances occurred on June 21, 2013. The two Emery combined cycle units were slow to respond and did not reach the offered capacity, which resulted in a CRDF charge of 583.12. The coal-fired Neal 3 unit had been ramping down in previous hours and was not able to change direction quickly enough when instructed to ramp up, resulting in a CRDF charge of $62. 72. IPL should be allowed to recover the CRDF charges in its rates. IPL follows good utility practices in maintaining its generating units, but even following good utility practices does not guarantee that a unit will always be responsive to control instructions in the exact manner expected. [87]

Interstate Electric additionally provided an Economic Savings Analysis for all four quarters of the reporting year in Attachment E. The economic savings are realized because Interstate Electric is longer required to "hold back" generators in order to provide ancillary services and can instead gain margin on the energy sales accrued by these generators. Prior to ASM, some low-cost coal generation had to be "held back" to allow Interstate Electric to self-provide ancillary services, which incurred an opportunity cost as the units could not be offered into the MISO market and garner a higher payment than the fuel and operating

[87] *Id*, Pages 20-21.

costs. Interstate Electric calculated these benefits, less the MISO Schedule 17 administrative costs for ASM, resulting in total net benefits of $1,766,626 for this reporting period.[88] In the prior two reporting periods, total net benefits were $2,378,965 for FYE12 and $1,314,507 for FYE11.

The Department believes that Interstate Electric has done a reasonable job with its ASM compliance filing and concludes that IPL's ASM reporting and charges via the FCA are reasonable based on our review. The DOC recommends that the Commission accept Interstate Electric's ASM reporting.

X. RECOMMENDATIONS

For Section III, Compliances, the Department recommends that the Commission accept the all compliance filings A to N, as discussed above, and requests information in Reply Comments from Interstate Electric for compliance filing N regarding quarterly filings of accounting costs for Auction Revenue Rights.

Regarding forced outages, the Department requests that utilities provide the following in reply comments to identify solutions to issues:

- How Minnesota and other utilities can share best practices across utilities in a timely manner (*e.g.*, videos as Xcel describes, electronic bulletins of best practices) to ensure that as many generation plants as possible maximize the days of operation and minimize the number of forced outages.
- Utilities should discuss any electronic databases that have been developed to share best practices in plant maintenance and repair.
- Utilities should discuss their efforts to obtain Business Interruption Insurance due to any factor that causes an unplanned outage or longer-than-expected planned outages.
- If utilities have not obtained Business Interruption Insurance, they should provide a full explanation as to why not.
- Utilities should discuss any revisions of language in contracts with contractors working on plants to increase the contractor's accountability in minimizing the length of the outage and ensuring that the plant runs smoothly.
- Utilities should discuss any efforts to recoup replacement power costs from contractors that worked on plants that subsequently had outages or any other source of reimbursement for replacement power costs.
- If utilities did not pursue any reimbursement for replacement power costs, utilities should provide a full explanation as to why not.
- Utilities should provide the dates and duration of their scheduled and forced outages by plant since 2001.
- Utilities should discuss the general factors utilities consider in scheduling planned outages.

[88] *Id,* Attachment E, "Energy Savings less Sch. 17 Charges ASM Allocation" for all four quarters in the reporting period

For Section V, Sherco 3, the Department appreciates that Xcel Electric is pursuing legal remedies. The Department also notes that this example raises an important question about the role that Business Interruption Insurance could play and, as noted above, has asked utilities to provide further information about this tool. During the legal process, additional facts may be developed through either briefs or discovery that are not available to date. Therefore, the Commission may want to retain the right to revisit this issue if additional facts developed during the legal process contradict the record to date.

For Section VII, Effects of the MISO Day 1 on Minnesota Ratepayers, the Department recommends the following:

- Overall the Department concludes that the Companies' responses have complied generally with all of the AAA MISO Day 1 compliance reporting requirements. The Department expects utilities to continue to work hard to mitigate costs or the effects of changes by MISO or FERC that could negatively impact Minnesota retail customers. Utilities are required to continue to show benefits of MISO Day 1 in the context of their rate cases before receiving cost recovery of Schedule 10 costs.

- The Department recommends that the Commission continue to require utilities to provide in the initial filing of all future electric AAA reports the Minnesota-jurisdictional Schedule 10 costs together with the allocation factor used and support for why the allocator is reasonable. Additionally, the Department recommends that the Commission continue to require utilities to provide information to support MISO Schedule 10 cost increases of five percent or higher over the prior year costs, including explanation of benefits received by customers for these added costs. This additional information would expedite the Department's review of MISO Day 1 costs in future electric AAA filings.

For Section VIII, Effects of the MISO Day 2, on Minnesota Ratepayers, the Department recommends the following:

<u>Xcel Electric</u>

- The Department notes that total system Congestion and Financial Transmission Rights (FTR) Charges increased significantly from $5,571,845 in FYE12 to $26,704,075 in FYE13. In addition, the Department notes that the percentage of Congestion and FTR Charges assigned to retail have increased from 79.5 percent ($4,428,773/$5,571,845) in FYE12 to 91.6 percent ($24,474,234/$26,704,075) in FYE13. As a result, the Department asks the Company to explain in reply comments the reason for this increase in total system Congestion and FTR Charges. In addition, the Department asks the Company to explain in reply comments why the percentage assigned to retail has increased from 79.5 percent in FYE12 to 91.6 percent in FYE13.

- The Department notes that total system MISO RSG Charges (revenues) more than tripled from ($946,446) in FYE12 to ($2,912,229) in FYE13. As a result, the Department asks the Company to explain this increase in total system MISO RSG Charges Revenues in reply comments.

- The Department notes that total system MISO ARR revenues nearly tripled from ($2,782,494) in FYE12 to ($7,774,930) in FYE13. The Department asks the Company to explain this increase in total system MISO ARR revenues in its reply comments.

- The Department recommends that Xcel Electric explain, in reply comments, if any of the Company's allocation methods have changed during the 2012-2013 reporting period. If so, the Department recommends that Xcel Electric explain, in reply comments, the nature of these changes, why changes is allocators are reasonable and superior allocator, and the effect these changes have had on the charges assigned to various customer categories in the 2012-2013 AAA Report.

- The Department recommends that the Commission not accept Xcel Electric's MISO Day 2 reporting at this time until the Company has provided the required information in its reply comments.

<u>Minnesota Power</u>

- The Department recommends that MP provides in reply comments the additional information requested regarding its January 2013 Day-Ahead Congestion Charges and that the Commission not accept MP's MISO Day 2 reporting until this information is assessed.

<u>Otter Tail Power</u>

- The Department recommends that OTP explain, in reply comments, why the total 2012-2013 MISO Day 2 charges increased from $28.0 million in 2011-2012 to $31.4 million in 2012-2013.

- The Department recommends that OTP explain, in reply comments, why the Company incurred such large Day Ahead Energy Losses (DA Loss Amt) in April, 2013 and why these costs are appropriately assigned to retail customers.

- The Department recommends that OTP explain, in reply comments, why the Company incurred increased Day Ahead and Real time Energy Losses in the July 2012 to June 2013 as compared to the previous year and why these costs are appropriately assigned to retail customers.

- The Department recommends that OTP explain, in reply comments, why the Company incurred such large Day Ahead Congestion (DA FBT Congestion Amt) costs in August, 2013 and why these costs are appropriately assigned to retail customers.

- The Department recommends that OTP explain, in reply comments, why the Company incurred such large RSG and Make Whole Payments costs in May, 2013 and why these costs are appropriately assigned to retail customers.

- The Department recommends that OTP explain, in reply comments, if any of the Company's allocation methods for MISO Day 2 charges changed during the 2012-2013 reporting period. If so, the Department recommends that OTP explain, in reply comments, the nature of these changes and the effect these changes have had on the charges assigned to various customer categories in the 2012-2013 AAA Report.

- The Department recommends that the Commission not accept OTP's MISO Day 2 reporting until the Company has provided the required information in its reply comments and the Department is able to review OTP's information.

Interstate Electric

- After reviewing Interstate Electric's responses to Department information requests, the Department recommends the Commission accept Interstate Electric's MISO Day 2 reporting.

For Section IX, Ancillary Services Market (ASM), the Department recommends the following:

- The Department notes that Xcel's total system ASM costs increased significantly from $10,665,160 in FYE12 to $22,631,901 for FYE13. As a result, the Department recommends that Xcel explain this increase in total system ASM costs in its reply comments.

- Given the significant year-over-year increase and the large Excessive/Deficient Energy Deployment Charges (EDEDC) amounts assigned to Sherco units 1 and 2, the Department recommends that Xcel explain in reply comments whether it has since reached any conclusions regarding the root cause for the large EDEDC amounts assigned to Sherco units 1 and 2. In addition, the Department recommends that Xcel continue to work with MISO to mitigate these costs in the future.

- Based on the Company's explanation above, the Contingency Reserve Deployment Failure Charges appear reasonable. However, the Department recommends that Xcel continue to work with MISO to mitigate these costs in the future.

- The Department recommendations that the Commission not accept Xcel Electric's ASM reporting at this time until the Company has provided the required information in its reply comments.

- The Department requests that the Commission accept MP's ASM reporting.

- The Department recommends that the Commission accept OTP's ASM reporting.

- The Department recommends that the Commission accept Interstate Electric's ASM reporting.

PUBLIC DOCUMENT

Department of Commerce, Division of Energy Resources

Attachments E1 through E12

Docket No. E999/AA-13-599

Attachment E1

IOUs' Fuel Cost Projections 2014-2018

Attachment E1

Fuel Cost Projections ($/MWh) for 2014 through 2018

$/MWh	2014	2015	2016	2017	2018
(1) Dakota	**[TRADE SECRET DATA HAS BEEN EXCISED]**				
(2) IPL					
(3) MP					
(4) OTP					
(5) Xcel Electric					

Annual and Cumulative Percent Change in Fuel Cost for 2015 through 2018

	2014	2015	2016	2017	2018	2014-2018
Dakota	**[TRADE SECRET DATA HAS BEEN EXCISED]**					
IPL						
MP						
OTP						
Xcel Electric						

Source:
(1) Exhibit D, page 2 of 2, Dakota's August 28, 2013 AAA report in Docket No. E999/AA-13-599.
(2) Exhibit E, page 2 of 2, IPL's September 3, 2013 AAA report in Docket No. E999/AA-13-599.
(3) Attachment 4, page 3 of 3, MP's August 30, 2013 AAA report in Docket No. E999/AA-13-599.
(4) Pages 129-134 of 204, OTP's August 30, 2013 AAA report in Docket No. E999/AA-13-599.
(5) Part G, Section 1, Schedule 1, pages 1-5 of 5, Xcel's September 3, 2013 AAA report in Docket No. E999/AA-13-599.

Attachment E2

Xcel Electric's Wind Curtailment Payments: FYE06 through FYE13

Source: Xcel's monthly FCAs and input data emails

Xcel	Wind Costs (l)	Curtailment Payments (m)	Curtailment Payments % (n)	Curtailment Payments ($/kWh) (o)
Jul-05	$ 2,209,107	$ 25,541	1.16%	0.00001
Aug-05	$ 1,518,401	$ 402	0.03%	0.00000
Sep-05	$ 2,980,966	$ 226,425	7.60%	0.00006
Oct-05	$ 2,672,444	$ 299,556	11.21%	0.00008
Nov-05	$ 3,246,917	$ 63,469	1.95%	0.00002
Dec-05	$ 2,310,360	$ 14,611	0.63%	0.00000
Jan-06	$ 3,181,045	$ 149,230	4.69%	0.00004
Feb-06	$ 2,928,149	$ 34,409	1.18%	0.00001
Mar-06	$ 3,225,927	$ 82,933	2.57%	0.00002
Apr-06	$ 3,277,251	$ 172,533	5.26%	0.00005
May-06	$ 3,420,464	$ 155,300	4.54%	0.00005
Jun-06	$ 1,794,434	$ 47,056	2.62%	0.00001
FYE06	$ 32,765,465	$ 1,271,465	3.88%	0.00003
Jul-06	$ 2,022,618	$ 21,751	1.08%	0.00000
Aug-06	$ 1,622,157	$ 49,915	3.08%	0.00001
Sep-06	$ 2,137,230	$ 21,205	0.99%	0.00001
Oct-06	$ 3,735,580	$ 187,961	5.03%	0.00005
Nov-06	$ 3,750,604	$ 96,229	2.57%	0.00003
Dec-06	$ 4,420,067	$ 145,404	3.29%	0.00004
Jan-07	$ 5,269,373	$ 253,194	4.81%	0.00007
Feb-07	$ 3,667,764	$ 88,835	2.42%	0.00003
Mar-07	$ 5,058,108	$ 82,644	1.63%	0.00002
Apr-07	$ 4,590,927	$ 152,683	3.33%	0.00005
May-07	$ 5,346,822	$ 545,568	10.20%	0.00016
Jun-07	$ 3,491,293	$ 504,074	14.44%	0.00013
FYE07	$ 45,112,543	$ 2,149,463	4.76%	0.00005

Xcel	Wind Costs	Curtailment Payments	Curtailment Payments %	Curtailment Payments ($/kWh)
	(l)	(m)	(n)	(o)
Jul-07	$ 2,409,324	$ 31,773	1.32%	0.00001
Aug-07	$ 1,923,872	$ 33,751	1.75%	0.00001
Sep-07	$ 4,869,010	$ 782,876	16.08%	0.00021
Oct-07	$ 5,442,224	$ 1,000,320	18.38%	0.00027
Nov-07	$ 8,214,094	$ 2,823,623	34.38%	0.00082
Dec-07	$ 6,291,719	$ 423,078	6.72%	0.00011
Jan-08	$ 8,362,879	$ 30,628	0.37%	0.00001
Feb-08	$ 7,021,419	$ 142,412	2.03%	0.00004
Mar-08	$ 7,816,746	$ 14,281	0.18%	0.00000
Apr-08	$ 10,118,928	$ 714,484	7.06%	0.00021
May-08	$ 8,781,452	$ 25,464	0.29%	0.00001
Jun-08	$ 5,840,030	$ 394,186	6.75%	0.00011
FYE08	$ 77,091,697	$ 6,416,876	8.32%	0.00014
Jul-08	$ 4,860,293	$ 25,680	0.53%	0.00001
Aug-08	$ 5,114,362	$ -	0.00%	0.00000
Sep-08	$ 7,195,808	$ 314	0.00%	0.00000
Oct-08	$ 8,287,796	$ 39,601	0.48%	0.00001
Nov-08	$ 9,236,754	$ 7,321	0.08%	0.00000
Dec-08	$ 11,364,844	$ 157,390	1.38%	0.00004
Jan-09	$ 9,589,360	$ 67,841	0.71%	0.00002
Feb-09	$ 9,301,276	$ 65,027	0.70%	0.00002
Mar-09	$ 9,116,584	$ 384,076	4.21%	0.00010
Apr-09	$ 9,657,360	$ 428,054	4.43%	0.00013
May-09	$ 8,707,682	$ 854,757	9.82%	0.00026
Jun-09	$ 5,200,532	$ 335,260	6.45%	0.00010
FYE09	$ 97,632,650	$ 2,365,322	2.42%	0.00005

Xcel	Wind Costs (l)	Curtailment Payments (m)	Curtailment Payments % (n)	Curtailment Payments ($/kWh) (o)
Jul-09	$ 4,415,900	$ 17,809	0.40%	0.00000
Aug-09	$ 5,166,096	$ 81,725	1.58%	0.00002
Sep-09	$ 4,536,909	$ 38,172	0.84%	0.00001
Oct-09	$ 6,681,288	$ 96,615	1.45%	0.00003
Nov-09	$ 8,659,367	$ 398,315	4.60%	0.00012
Dec-09	$ 6,168,879	$ 21,765	0.35%	0.00001
Jan-10	$ 8,659,367	$ 15,380	0.18%	0.00000
Feb-10	$ 6,168,879	$ 43,617	0.71%	0.00001
Mar-10	$ 9,796,100	$ 130,620	1.33%	0.00004
Apr-10	$ 10,043,080	$ 318,281	3.17%	0.00010
May-10	$ 9,458,060	$ 189,651	2.01%	0.00006
Jun-10	$ 6,363,014	$ -	0.00%	0.00000
FYE10	$ 86,116,937	$ 1,351,950	1.57%	0.00003
Jul-10	$ 5,889,422	$ 30,218	0.51%	0.00001
Aug-10	$ 7,999,951	$ 1,118,405	13.98%	0.00026
Sep-10	$ 8,204,135	$ 755,635	9.21%	0.00023
Oct-10	$ 8,956,519	$ 90,191	1.01%	0.00003
Nov-10	$ 10,639,220	$ 18,314	0.17%	0.00001
Dec-10	$ 8,262,040	$ 67,164	0.81%	0.00002
Jan-11	$ 8,685,186	$ 8,352	0.10%	0.00000
Feb-11	$ 11,805,336	$ 57,676	0.49%	0.00002
Mar-11	$ 9,357,485	$ 40,590	0.43%	0.00001
Apr-11	$ 10,904,234	$ 39,573	0.36%	0.00001
May-11	$ 12,596,208	$ 23,328	0.19%	0.00001
Jun-11	$ 8,578,212	$ 61,634	0.72%	0.00002
FYE11	$ 111,877,948	$ 2,311,080	2.07%	0.00005

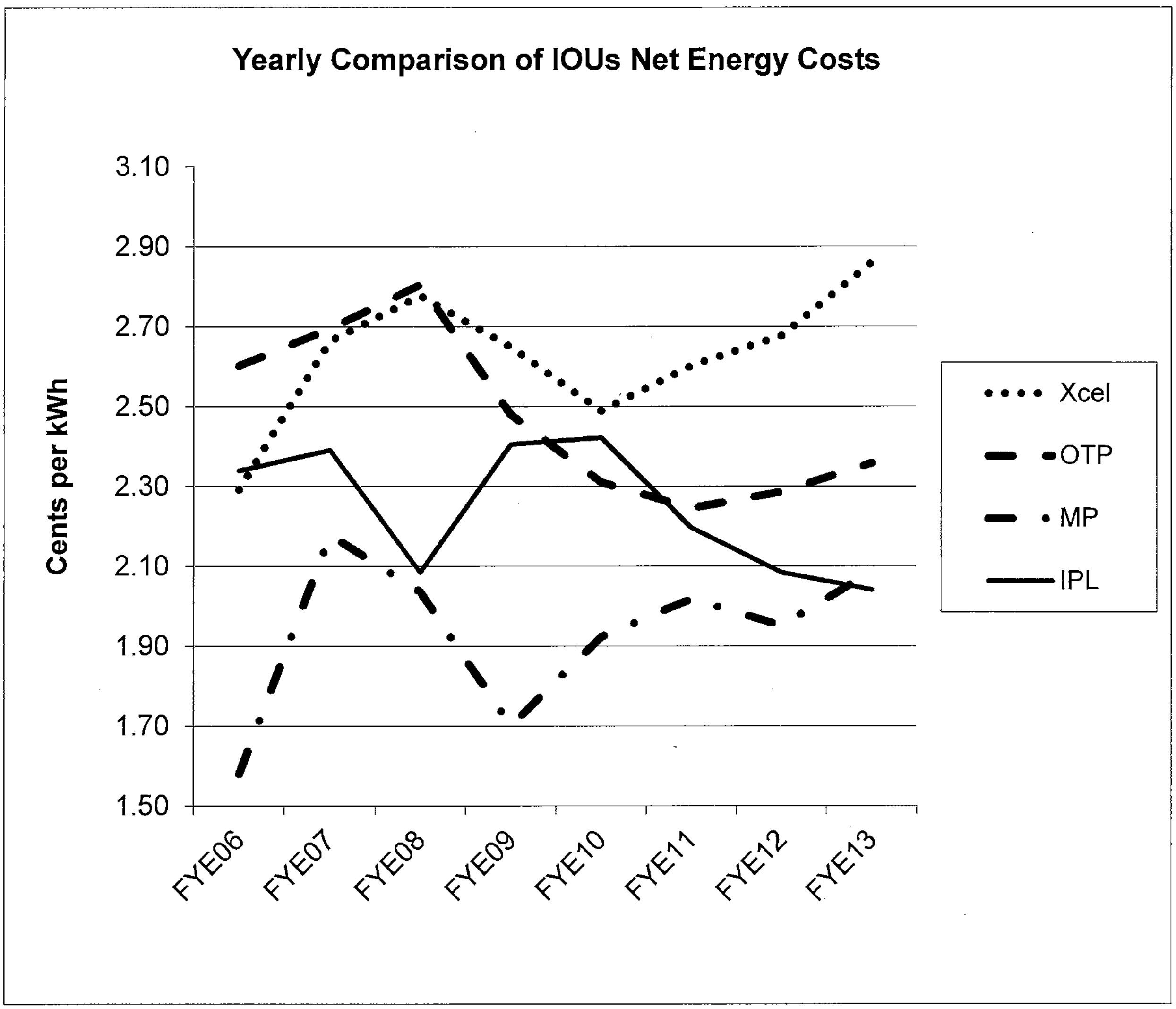
Xcel	Wind Costs (l)	Curtailment Payments (m)	Curtailment Payments % (n)	Curtailment Payments ($/kWh) (o)
Jul-11	$ 4,505,969	$ -	0.00%	0.00000
Aug-11	$ 4,423,991	$ -	0.00%	0.00000
Sep-11	$ 5,797,516	$ 89,862	1.55%	0.00003
Oct-11	$ 11,041,598	$ 286,768	2.60%	0.00009
Nov-11	$ 13,146,681	$ 119,855	0.91%	0.00004
Dec-11	$ 11,628,278	$ 119,830	1.03%	0.00003
Jan-12	$ 13,985,009	$ 116,974	0.84%	0.00003
Feb-12	$ 10,356,745	$ 165,746	1.60%	0.00005
Mar-12	$ 13,410,686	$ 803,846	5.99%	0.00024
Apr-12	$ 13,309,148	$ 165,777	1.25%	0.00005
May-12	$ 12,620,061	$ 10,936	0.09%	0.00000
Jun-12	$ 10,014,738	$ 391,704	3.91%	0.00011
FYE12	$ 124,240,420	$ 2,271,297	1.83%	0.00005
Jul-12	$ 6,814,010	$ 33,320	0.49%	0.00001
Aug-12	$ 7,042,214	$ 2,177	0.03%	0.00000
Sep-12	$ 8,726,353	$ 70,346	0.81%	0.00002
Oct-12	$ 13,725,930	$ 60,073	0.44%	0.00002
Nov-12	$ 13,638,084	$ 283,709	2.08%	0.00008
Dec-12	$ 11,980,060	$ 237,727	1.98%	0.00007
Jan-13	$ 15,856,086	$ 99,847	0.63%	0.00003
Feb-13	$ 12,736,724	$ 77,831	0.61%	0.00002
Mar-13	$ 13,303,380	$ 241,879	1.82%	0.00007
Apr-13	$ 14,854,438	$ 607,745	4.09%	0.00019
May-13	$ 14,708,628	$ 443,050	3.01%	0.00014
Jun-13	$ 11,102,318	$ 270,229	2.43%	0.00008
FYE13	$ 144,488,225	$ 2,427,933	1.68%	0.00006

Attachment E3

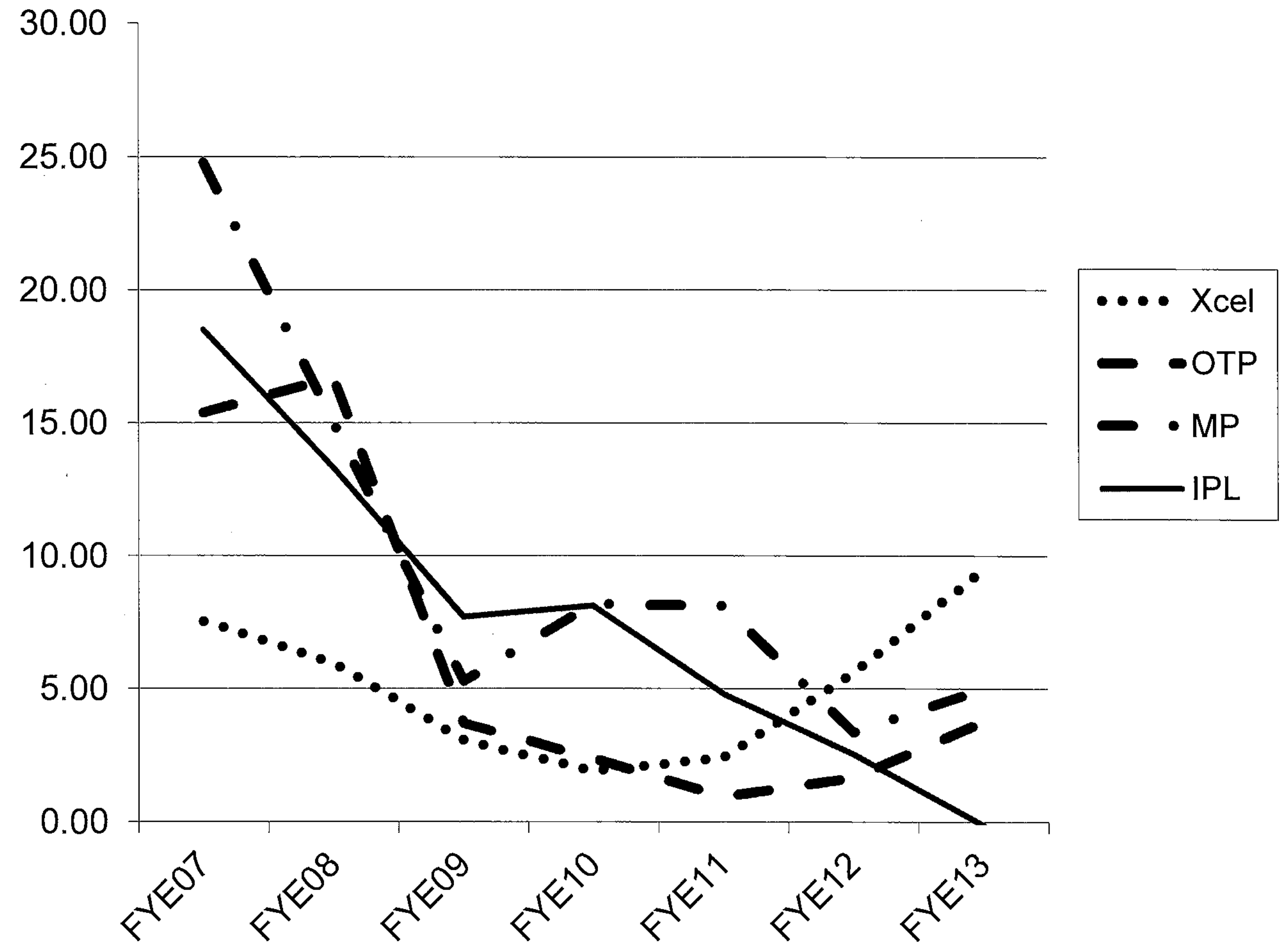
Annual Comparison of IOUs Net Energy Costs and Outages Costs: FYE06 through FYE13

Utilities Fuel and Purchased Power Costs in cents per kWh

Cents/kWh	Xcel	OTP	MP	IPL
FYE06	2.29	2.60	1.58	2.34
FYE07	2.66	2.69	2.18	2.39
FYE08	2.78	2.81	2.04	2.09
FYE09	2.65	2.48	1.70	2.41
FYE10	2.49	2.31	1.92	2.42
FYE11	2.60	2.24	2.02	2.20
FYE12	2.68	2.29	1.95	2.08
FYE13	2.86	2.36	2.09	2.04
Min	2.29	2.24	1.58	2.04
Max	2.86	2.81	2.18	2.42



Yearly Comparison of IOUs Outages Costs in Percentage of Fuel and Purchased Power Costs



Attachment E4

IOUs Maintenance Expenses of Generation Plants: 2005-2012

Maintenance Expenses of Generation Plants: 2005-2012

	Docket/ Test Year	Rate Case (a)	2005	2006	2007	2008	2009
IPL	10-276/2009	$ 3,779,345	$ 3,096,585	$ 2,737,232	$ 2,906,925	$ 3,834,111	$ 3,015,487
MP	09-1151/2010	$ 33,619,194	$ 24,413,532	$ 29,556,035	$ 34,498,017	$ 29,819,678	$ 29,031,118
Xcel	12-961/2013	$ 173,413,367	$ 124,705,555	$ 138,916,698	$ 144,317,233	$ 128,411,240	$ 150,857,274
OTP	10-239/2010	$ 13,142,720	$ 9,017,424	$ 11,871,158	$ 10,444,219	$ 12,981,917	$ 12,911,918

	2010 (b)	2011 (c)	2012 (d)	3-year average (e)	Rate Case (a)	Difference (f)
IPL	$ 3,173,210	$ 3,593,908	$3,405,372	$ 3,390,830	$ 3,779,345	$ (388,515)
MP	$ 45,307,981	$ 45,683,871	$42,970,316	$ 44,654,056	$ 33,619,194	$ 11,034,862
Xcel	$ 169,389,054	$ 179,143,695	$176,598,518	$ 175,043,756	$ 173,413,367	$ 1,630,389
OTP	$ 10,255,211	$ 12,014,142	$11,653,436	$ 11,307,596	$ 13,142,720	$ (1,835,124)

(e) = ((b) + (c) + (d))/3
(f) = (e) - (a)

Attachment E5

Summary of the Department's Investigation of the IOUs' FYE11 Forced Outages

Summary of Department's Investigation of IOUs' FYE11 Forced Outages
Docket No. E999/AA-11-792

Safety Relief Valve (SRV) leak at Monticello

- Xcel's Minnesota ratepayers were charged $334,100 in increased energy costs as a result of a forced four-day outage to replace the SRV at the Monticello plant. The SRV prevents the primary system piping from being over-pressurized.
- Between 1984 and 1993, there were three instances similar to the 2011 occurrence where elevated tailpipe temperatures were present following testing of the valve during startup that required SRV replacement.
- In 2004, the American Society of Mechanical Engineers code was revised to no longer require SRVs to be opened and closed at reduced or normal system pressure following maintenance.
- As a result, Xcel asked the Nuclear Regulatory Commission in February 2012 to allow Xcel to manually activate the SRVs during plant startup.
- Xcel provided no analysis to support its decision to wait until its "normal industry update" to adopt "the new method for testing SRVs at that time." The only justification provided was that "it is not common within the industry to request approval for alternative forms of testing from the NRC, especially when our normal industry update was soon approaching and we planned on adopting the new method for testing SRVs at that time."

Coal bunker explosion at Black Dog

- Xcel's Minnesota ratepayers were charged $326,300 in increased energy costs as a result of a forced outage resulting from a coal bunker explosion due to the buildup of carbon monoxide at the Black Dog plant.
- Three similar instances occurred at the King plant in 2007, 2008 and 2009. The preventive steps developed in response to these forced outages were only applied to the King plant.
- Xcel waited until 2010 to assess all coal-plant handling processes for risk relative to CO explosions. According to Xcel, there have been no CO explosion events at plants on the NSP-Minnesota system since then.
- Xcel provided no analysis to support its conclusion that "the actions we took at King were not seen as necessary, or prudent, to apply across the system absent a clear need to do so."

Use of Incompatible O-rings by a Contractor at Boswell

- MP's ratepayers were charged $507,715 in increased energy costs as a result of a forced outage resulting from replacement o-rings made of materials incompatible with the fluids used in the hydraulic system at the Boswell Energy Center.

- MP informed the vendor that all o-rings and seals were to be replaced and that viton was the only acceptable material.

- According to MP, viton o-rings were a different color so it was easy to tell one material from another. However, now they can be any color. To alleviate the potential confusion, MP purchased a tester to determine the material of o-rings.

- No red flags appear to have been raised to take into account the change in the color of the o-rings. Even if such a red flag was raised, MP provided no analysis to justify why it has not purchased a tester sooner.

- According to MP, there was no reason to add to the cost of the rebuild by having an engineer watch the entire rebuild process (5 weeks). However, MP provided no analysis to support its conclusion that "this cost could not be justified."

Incorrect Assembly of Water Pump Suction Valves by a Contractor at Boswell

- MP's ratepayers were charged $161,187 in increased energy costs as a result of a forced outage resulting from the incorrect assembly of water pump suction valves at the Boswell Energy Center.
- As a result of similar issues with other pumps repaired by vendors, MP will increase inspection work both onsite and at the vendor's facility.
- MP provided no analysis to support the action chosen: no action.

Employee error at King, Sutherland and Prairie Creek

- Xcel's Minnesota ratepayers were charged $61,300 in increased energy costs as a result of a forced outage resulting from an allen wrench that fell in the bus duct work due to an employee error.
- As a result, a work order was created to cover the buss duct opening. All material going in and out of the exciter will be signed in and out.
- Xcel also created a Plant Management Directive outlining sensitive areas where sign-in and sign-out of equipment is required. However, Xcel still has not clarified whether and when similar measures were taken at all plants on Xcel's system.

- IPL's Minnesota ratepayers were charged $55,656 in increased energy costs as a result of a forced outage resulting from an oil pump failure due to an employee error.
- The pump failed when a valve was left in the closed position, reducing oil flow to the turbine bearings.
- According to IPL, the development of an organization to operate at a zero failure level would require more staff and higher levels of training, and testing than customers may be willing to support. However, IPL provided no analysis showing that the costs of the training system IPL put in place after the error were higher than the $1,012,357 in replacement power cost that were charged to all ratepayers as a result of the outage.

- IPL's Minnesota ratepayers were charged $8,460 in increased energy costs as a result of a forced outage resulting from a primary air fan fire due to an employee error.
- According to IPL, the coal pulverizing mill should have been immediately shut down when the mill became plugged.

- Xcel and IPL have not shown that they had a reasonable system in place prior to these incidents.

Attachment E6

Outage Cost of Sherco 3: November 2011-December 2013

Outage Cost of Sherco 3

	Change in Energy Costs due to Sherco 3 Outage	Source: Attachment 1, Docket Number
Nov-11	**[Trade Secret**	E002/AA-11-1305
Dec-11	**Data Excised]**	E002/AA-12-105
Jan-12		E002/AA-12-172
Feb-12		E002/AA-12-314
Mar-12		E002/AA-12-433
Apr-12		E002/AA-12-556
May-12		E002/AA-12-717
Jun-12		E002/AA-12-857
Jul-12		E002/AA-12-935
Aug-12		E002/AA-12-1057
Sep-12		E002/AA-12-1171
Oct-12		E002/AA-12-1308
Nov-12		E002/AA-12-1376
Dec-12		E002/AA-13-95
Jan-13		E002/AA-13-152
Feb-13		E002/AA-13-242
Mar-13		E002/AA-13-331
Apr-13		E002/AA-13-450
May-13		E002/AA-13-571
Jun-13		E002/AA-13-645
Jul-13		E002/AA-13-776
Aug-13		E002/AA-13-915
Sep-13		E002/AA-13-1016
Oct-13		E002/AA-13-1099
Nov 2011-Oct 2013	$ -	
Nov-13		E002/AA-13-1177
Dec-13		E002/AA-14-103
Nov 2011-Dec 2013	$ -	

Attachment E7

January 27, 2014 Joint Amended Complaint against General Electric Entities

to

Recover Costs Associated with Sherco 3 Outage

STATE OF MINNESOTA
COUNTY OF SHERBURNE

DISTRICT COURT
TENTH JUDICIAL DISTRICT
CASE TYPE: PROPERTY DAMAGE

NORTHERN STATES POWER COMPANY, SOUTHERN MINNESOTA MUNICIPAL POWER AGENCY; AEGIS INSURANCE SERVICES, LTD. and other Interested Insurers as subrogees of Northern States Power Company,

Plaintiffs,

Case No: 71-CV-13-1472
Hon. Sheridan Hawley

v.

GENERAL ELECTRIC COMPANY; GENERAL ELECTRIC INTERNATIONAL, INC.; GE ENERGY SERVICES, INC.; and GE ENERGY CONTROL SOLUTIONS, INC.,

Defendants.

AMENDED COMPLAINT

Northern States Power Company (NSP) and Southern Minnesota Municipal Power Agency (SMMPA), joint owners of Unit 3 at the Sherburne County Generating Station; and AEGIS Insurance Services, Ltd., Energy Insurance Mutual Limited, ACE American Insurance Company, American Alternative Insurance Corporation, AEGIS London Group, and other London and Lloyd's Market Insurers, all insurers of the Sherburne County Generating Station (collectively the Interested Insurers) complain against General Electric Company, General Electric International, Inc., GE Energy Services, Inc., and GE Energy Control Solutions, Inc. as follows:

NATURE OF THE ACTION

1. This lawsuit involves the Low Pressure (LP) turbine of a G3 tandem compound steam turbine (Unit 3) that catastrophically failed on November 19, 2011, at the Sherburne County Generating Station (Sherco) in Becker, Minnesota. General Electric Company and General Electric-related entities designed, marketed, manufactured, and sold the LP turbine and at various times serviced the LP turbine.

2. The LP turbine's catastrophic failure caused substantial damage to Unit 3's other turbines, the generator, the exciter, and other property at Sherco.

3. Plaintiffs' investigations concluded that defendants' acts and omissions, as detailed in this Amended Complaint, caused the LP turbine to fail catastrophically.

4. Plaintiffs seek damages arising from and proximately caused by defendants' grossly negligent, willful, wanton, reckless, and fraudulent conduct, malpractice and other acts and omissions.

PARTIES

5. NSP is a Minnesota corporation with a principal place of business in Minneapolis, Minnesota.

6. SMMPA is a Minn. Stat. Ch. 453 Minnesota municipal power agency that generates and supplies electricity and power to supply eighteen non-profit, municipally-owned member utilities located throughout Minnesota. SMMPA's principal place of business is Rochester, Minnesota.

7. An ownership and operating agreement between NSP and SMMPA designates NSP as project manager of Unit 3 and defines the parties' respective Unit 3 rights and obligations.

8. The following Interested Insurers are also plaintiffs in this action by reason of providing property insurance for the benefit of the Sherco facility, including Unit 3. The Interested Insurers' respective policies insured the Sherco facility against risk of loss, and the Interested Insurers are subrogated to the interests of their insureds by having made payments as required by their respective contracts of insurance as follows:

a. AEGIS Insurance Services, Ltd. (AEGIS, Ltd.), a foreign corporation domiciled in Bermuda, provided insurance coverage for Sherco under policy no. L0969A1A11.

(1) As a result of the November 19, 2011 failure, AEGIS, Ltd. has made payments to restore damaged property.

(2) AEGIS, Ltd. is subrogated to the extent of payments made to its insureds.

b. Energy Insurance Mutual Limited (EIM), a foreign corporation domiciled in Bridgetown, Barbados with a principal place of business in Tampa, Florida, provided insurance coverage for Sherco under policy no. 310565-11GP.

(1) As a result of the November 19, 2011 failure, EIM made payments to restore damaged property.

(2) EIM is subrogated to the extent of payments made to its insureds.

c. ACE American Insurance Company, a Pennsylvania corporation with a principal place of business in Philadelphia, Pennsylvania, provided insurance coverage for Sherco under policy no. EUTN05105602.

(1) As a result of the November 19, 2011 failure, ACE made payments to restore damaged property.

(2) ACE is subrogated to the extent of payments made to its insureds.

d. American Alternative Insurance Corporation (AAIC), a Delaware corporation with principal place of business in New Jersey, provided insurance coverage for Sherco under policy no. 58A2PP000001302.

(1) As a result of the November 19, 2011 failure, AAIC made payments to restore damaged property.

(2) AAIC is subrogated to the extent of payments made to its insureds.

e. Certain London and Lloyd's Market Insurers—led by AEGIS London and including ACE London, Travelers London, Hiscox London, and Argenta London—all foreign corporations, provided insurance coverage in various proportions for Sherco under policy no. DG094311.

(1) As a result of the November 19, 2011 failure, the subscribing London and Lloyd's Market Insurers made payments to restore damaged property.

(2) The subscribing London and Lloyd's Market Insurers are subrogated to the extent of payments made to their insureds.

9. General Electric Company is a New York corporation with a principal place of business in Schenectady, New York.

10. General Electric International, Inc. is a Delaware corporation with a principal place of business in Shelton, Connecticut.

11. GE Energy Services, Inc. is a Delaware corporation with a principal place of business in Atlanta, Georgia.

12. GE Energy Control Solutions, Inc. is a Delaware corporation with a principal place of business in Longmont, Colorado.

13. The General Electric corporate entities named in this lawsuit at various times provided machinery and equipment for the Sherco facility, including Unit 3, and worked in concert to provide technical information for, monitoring of, and service to Unit 3.

JURISDICTION AND VENUE

14. This Court has personal jurisdiction over defendants because defendants conducted business in Minnesota, specifically at the Sherco facility in Sherburne County.

15. This Court has subject matter jurisdiction over this action because this lawsuit involves tort, gross negligence, willful and wanton negligence, malpractice, and

intentional wrongdoing, as well as fraudulent concealment that inflicted damages of more than $50,000.

16. Venue is proper because a substantial portion of the events, acts, and omissions that give rise to the lawsuit took place in Sherburne County and because defendants conducted business with NSP and SMMPA in Sherburne County.

FACTUAL ALLEGATIONS

I. The purchase and installation of Unit 3

17. The Sherco facility is one of the nation's largest electric generating plants—in terms of square feet, steam production, and power generation. The three Sherco units generate enough energy to power about two million households.

18. NSP built the Sherco facility in the 1970s to meet the growing demand for electricity and to reduce energy supply reliance on older, less efficient plants. NSP constructed the plant, originally consisting of two electrical generating units—each with production capability of 750 megawatts—on a 4,500-acre site.

19. In the late 1970s, NSP determined that Sherco generating capacity should be increased. Accordingly, NSP contracted with General Electric Company to design and build an additional generating unit. General Electric Company thereafter manufactured and sold the equipment and machinery that became Unit 3. When installed that equipment and machinery would enable NSP to increase the electric energy generating capacity at Sherco.

20. The Unit 3 equipment and machinery that the General Electric Company sold to NSP included the LP turbine that failed.

21. In 1983, SMMPA, United Minnesota Municipal Power Agency (UMMPA), and NSP contracted to be joint owners of Unit 3. In 1984 UMMPA assigned all Unit 3 rights, title, and interest to SMMPA, and SMMPA assumed all of UMMPA's Unit 3 obligations. As a result SMMPA ultimately took title to 41% of Unit 3, and to serve member cities SMMPA is entitled to take that percentage of the electric power and energy generated by Unit 3. By agreement between SMMPA and NSP, even though SMMPA owns 41% of Unit 3 and is entitled to take 41% of the power and energy produced from Unit 3, NSP operates Unit 3, as the project manager, for both owners.

22. In 1984, by a separate contract, a non-GE entity assembled and installed the equipment and machinery that became Unit 3. The purchase and installation of Unit 3 equipment and machinery cost NSP and SMMPA approximately $1 billion, which at the time made the project the largest of its kind in Minnesota.

23. As built, Unit 3 includes a high-pressure (HP) turbine, a double flow intermediate pressure (IP) turbine, two double-flow low-pressure (LP) turbines, and a two-pole 60 cycle generator.

II. Wilson Line failures

24. Steam rotates the separate Unit 3 turbines. After leaving a recirculating drum in the boiler, superheated steam passes through the HP turbine. Expanding steam acquires high velocity and exerts force on the turbine blades (called "buckets" in GE documents).

25. After leaving the HP turbine, the steam is reheated and thereafter passes through the IP turbine and then through the two LP turbines. From the LP turbines,

steam enters the condensers to be condensed back into water, which is then re-circulated through the boiler.

26. In the LP turbines, the steam passes through a series of blade rows, designated L-5 through L-0. The designation "L-," or "Last-Minus" denotes the location of the blade row in relation to the exhaust end of the rotor.

27. While expanding through the LP turbines, the steam crosses the saturation line, where the water transitions from dry (gas) to wet (liquid). The region in which steam begins to condense is called the phase transition zone (PTZ) or the Wilson Line. Depending upon turbine configuration, this zone can be at or around the L-1 stage.

28. When steam becomes wet, moisture penetrates the areas where turbine blades are inserted into the rotor wheel (called the "dovetail" in GE documents). This condensation concentrates normal steam contaminants, which in combination with operating stress and susceptible rotor wheel materials, can cause stress corrosion cracking (SCC). If undetected and unabated, SCC will lead to catastrophic rotor wheel failure.

29. The frequency of SCC failures has multiplied as turbine manufacturer designs have incorporated larger and heavier blades and increased blade loading: additional mass and loading dramatically intensifies stress on the rotor wheels at the dovetails.

30. The General Electric Company and other manufacturers have been aware of the problem of SCC in LP turbines since at least the 1960s. But information pertaining to SCC has been carefully guarded and controlled by General Electric Company and General Electric-related entities, and data relating to such failures have neither been

completely nor readily disseminated to NSP for itself and as Unit 3 project manager on SMMPA's behalf or made publicly available.

III. The history of fraudulent concealment

31. Before 2011, General Electric Company and General Electric-related entities possessed a specialized knowledge about the risks of SCC-related failure associated with the finger dovetails in the LP turbine, and had the opportunity to warn NSP for itself and as Unit 3 project manager on SMMPA's behalf about the need for periodic and proper inspection of the LP turbine rotor wheels. Because of the risks associated with SCC, General Electric Company developed an improved LP turbine rotor wheel design. Despite such knowledge and developments General Electric Company never properly warned NSP for itself and as project manager on SMMPA's behalf about the threat of SCC or the proper means to detect SCC, even though General Electric Company and its affiliates had numerous opportunities to do so while servicing Unit 3 or by means of Technical Information Letters (TILs) provided to customers. Those TILs routinely advised customers of known risks and precautionary measures to mitigate such risks.

A. Servicing Unit 3

32. Throughout the life of Unit 3, various General Electric related entities performed maintenance and services on Unit 3 and the Unit 3 LP turbines, including LP turbine inspections. These undertakings took place during scheduled Unit 3 outages.

33. All work was performed under and governed by various individual contracts, all of which were subject to a broader General Conditions Agreement between

NSP and the General Electric Company. The work specified by these individual contracts included:

a. comprehensive inspection of the LP and other turbines in 1999 conducted by the General Electric Company, GE Energy Services, and General Electric International, Inc.;

b. participation in inspections and repairs of Unit #3 in 2002, 2005 and 2008 by the General Electric Company;

c. evaluation of Unit #3 performance in 2009 by General Electric International, Inc.

d. repairs of Unit #3 in 2011 by GE Control Solutions, Inc. and GE International, Inc.

34. Before these and other outages, NSP employees and individuals who identified themselves as representatives of "GE" would conduct pre-outage meetings, at which time the scope of work for the project would be determined. The information provided by these "GE" representatives during pre-outage meetings, as well as by the Technical Information Letters issued by General Electric Company and General Electric-related entities, significantly influenced the formulation of outage-scopes-of-work, even when a General Electric-related entity did not ultimately perform the jobs.

35. The General Electric related entities meeting and communicating with NSP and performing work on Unit 3 possessed special knowledge about the risks of SCC-related failure and had the opportunity to warn NSP for itself and as Unit 3 project manager on SMMPA's behalf about the need for periodic and proper inspection of the LP

turbine rotor wheels (including magnetic particle testing, which General Electric Company describes as the "most reliable test" to detect internal SCC). No person or entity affiliated with General Electric ever gave such a warning.

B. General Electric's 494 Patent

36. While General Electric entities were servicing and providing technical information about Unit 3, General Electric Company was fully aware of design problems that caused dovetail integrity on the LP turbine rotor wheels, like the one at Unit 3, to be compromised by SCC. As a result General Electric Company developed a new design to make LP turbine rotor wheels less susceptible to SCC. In 2005, the General Electric Company sought to patent this improved design.

37. On June 17, 2008, the U.S. Patent office issued U.S. Patent No. 7,387,494 (the '494 Patent). The patent acknowledges prior rotor wheel design defects, explaining that "finger dovetails operate in an environment that is conducive to stress corrosion cracking (SCC)" and that rotor wheels were particularly susceptible "because the materials used for the rotors are much less resistant to SCC than are the materials used for the buckets."

38. The '494 Patent changes the dovetail system design as follows: "[t]he fillets on the wheel fingers and slot bottoms have a blend of different radii with the larger radii outward of the smaller radii to reduce stress concentrations and to avoid stress corrosion cracking." The changed design redistributes and reduces the inherent stress on the LP rotor wheels at the dovetails.

39. Despite possessing special knowledge about the new dovetail design and the reasons why the design needed to be modified, no employee of General Electric Company or any General Electric-related entity providing equipment and services at Unit 3 ever informed NSP for itself and as Unit 3 project manager on SMMPA's behalf about the design change, and neither General Electric Company nor any General Electric-related entity ever offered the revised design as a replacement option for the LP turbine rotor wheel that catastrophically failed. Despite securing a new rotor wheel patent in 2008, General Electric Company and General Electric-related entities also failed to advise NSP for itself and as project manager on SMMPA's behalf about the design defects and potential hazards associated with the LP rotor wheel.

40. Ironically, the modified dovetail design for which General Electric Company received a patent in 2008 is the exact method General Electric Company employed to make the repairs to the damaged Unit 3 LP turbine L-1 rotor wheels in 2012-13.

C. Technical information letters

41. Each TIL issued by General Electric Company or a General Electric-related entity bears a designated number and addresses issues that may pertain to a particular unit or General Electric's overall turbine fleet. General Electric Company determines which individual TIL is applicable to the various turbine models. General Electric Company then provides each customer with an online database of all TILs applicable to that customer's turbines.

42. On October 2, 2013, two years after the Unit 3 catastrophically failed, the General Electric Company issued TIL 1886. TIL 1886 warns operators of recirculating boilers (such as Unit 3) about the same SCC-related concerns that General Electric Company and General Electric Services had restricted to "once through" boilers in TIL 1277-2, fourteen years earlier. TIL 1277-2 did not become part of Unit 3 data base because Unit 3 does not include a "once through" boiler.

43. TIL 1886 advises that SCC has been detected in LP turbine rotor wheels "over the past several years," and that General Electric Company was aware of "over 60" incidents of similar SCC problems experienced by various customer's LP turbines.

44. TIL 1886 recommends inspection of all LP rotor wheels "at the next scheduled exposure of the line pressure rotor" and acknowledges that failure to perform the recommended periodic and proper inspection of the LP turbine rotor wheels (which would include magnetic particle testing) could "result in substantial damage to adjacent equipment and in some circumstances, possibly serious injury to any nearby personnel."

45. Despite General Electric Company and General Electric-related entities' extensive knowledge of "over 60" SCC incidents in LP turbine rotor wheels, and despite the numerous opportunities to disclose the dangerously defective design of existing LP turbine rotor wheels before November 29, 2011, General Electric Company and General Electric-related entities failed to disclose such defects or the need to conduct proper inspection to NSP for itself and as project manager on SMMPA's behalf.

46. In fact, an earlier TIL issued by the General Electric Company, TIL No. 1121-3AR1 issued to recirculating boiler operators, recommended against inspections to

detect SCC in rotor dovetails, which involve the difficult, expensive, and time consuming task of removing the blades for inspection, "unless abnormal events or operational anomalies occur." Unit 3 never experienced an abnormal event or operational anomaly, as specified by General Electric Company's TILs, before the November 19, 2011 catastrophic failure.

IV. Catastrophic failure of Unit 3

47. During the 2011 outage, NSP retained contractors to upgrade the Unit 3 HP and IP turbines.

48. NSP was led to believe that the LP turbines were not in need of significant servicing due to (1) the technical information provided by General Electric Company in TIL 1121-3AR1 and other TILs; (2) the recommendations provided by "GE" representatives during pre-outage meetings; and (3) the failure by all defendants to provide adequate warning about SCC risks and the need for periodic and proper inspections to detect SCC in the LP turbine rotor wheels. The scope-of-work to be performed during the 2011 outage, therefore, only called for visual inspection of the LP rotor.

49. After the contractors completed work on the HP and IP turbines and the exciter and uprated the generator, NSP re-fired Unit 3 for preliminary testing. During the first November 17, 2011 test, the unit attained running speed of 3,600 RPM. The operators noted no significant problems.

50. The next day, Unit 3 again rolled up to speed. Thereafter, NSP synchronized and loaded the unit to 240 MW for overnight heat soaking. Again, the operators detected no significant problems.

51. On Saturday, November 19, 2011, NSP took the unit off line for routine overspeed checking. Following the standard industry protocol the operators gradually accelerated the unit up to 3900 RPM.

52. As the unit operated in an overspeed mode, an electrician on the turbine floor heard a loud bang in the LP-B section. Within seconds, the massive unit shook violently, debris flew through the air, and flames rose from the unit. Thereafter, Unit 3 ground to a halt.

53. The massiveness of the failure and seriousness of the incident are difficult to imagine, much less describe. The machinery and equipment that make up Unit 3 rumbled and shook, spewing material throughout the turbine area and into the control room. Fires raged, and but for the heroics of Unit 3 operators the hydrogen used in the Unit might have caused an even larger explosion. More critically, NSP and contractor workers in the vicinity of Unit 3 could have sustained serious personal injury or been killed.

54. This destruction and calamity could have been prevented if General Electric Company, the "GE" representatives attending pre-outage meetings, or any of the General Electric-related entities providing technical information to and performing service on Unit 3 had fully disclosed to NSP for itself and as Unit 3 project manager on SMMPA's behalf what General Electric and General Electric-related entities and personnel had

known for decades about SCC, the need for periodic and proper magnetic particle testing of the rotor wheel dovetails, and the potential for LP turbine catastrophic failure.

V. Damage to the Sherco facility

55. The catastrophic failure and resulting fire caused damage to the following property and equipment:

a. Unit 3 turbine and generator controls, instrumentation, and auxiliary systems;

b. the Unit 3 HP turbine;

c. the Unit 3 IP turbine;

d. the Unit 3 LP turbines;

e. the Unit 3 generator;

f. the Unit 3 exciter;

g. the Unit 3 condensers;

h. mechanical and electrical equipment, as well as ductwork and control wiring;

i. various portions of the roof;

j. the Unit 3 control room;

k. various tools and equipment located in the vicinity of Unit 3; and

l. smoke and soot throughout the Sherco facility.

56. The catastrophic failure and resulting damage took Unit 3 out of operation for nearly two years. As a result: (i) to serve customers NSP and SMMPA were forced to purchase power and energy on the open wholesale electricity market at additional

expense; (ii) NSP and SMMPA were forced to forego revenues from the sale of energy that would have been produced by Unit 3 into the same market; (iii) NSP and SMMPA have incurred and in the future may continue to incur the cost of acquiring replacement capacity to ensure that sufficient electrical power and energy is available to meet peak demand loads; (iv) likewise, in the future, NSP and SMMPA may be assigned a diminished capacity credit compared to Unit 3's historical average, which could result in higher operational costs; and (v) NSP and SMMPA may incur additional costs necessary to manage changes in coal supply requirements, including expenses associated with idling and storing unit train sets.

57. The repair of Unit 3 and the Sherco facility, substantially funded by the Interested Insurers, and the costs incurred by NSP and SMMPA as a result of Unit 3 being out of operation, greatly exceed $50,000.

VI. Investigation of the failure

58. After the catastrophic failure, plaintiffs retained a number of consultants to investigate causation.

59. A metallurgical evaluation determined that SCC on the LP turbine rotor wheel caused the catastrophic failure. Specifically, testing revealed that SCC propagated on the L-1 rotor wheel where the dovetail fingers changed thickness and from the holes where locking pins attach the blades to the rotor wheel.

60. Careful scrutiny revealed that under normal operating conditions the design of the rotor wheel blade attachments was technically flawed – i.e. destined to fail.

61. The retained consultants also observed significant SCC not only at the L-1 stage rotor wheel that failed, but also in the three wheels that had not yet failed. Hence, if the LP-B, L-1 rotor wheel had not failed, another rotor wheel would inevitably have failed.

62. If General Electric Company, the "GE" representatives, or any of the General Electric-related entities performing service on or providing technical information regarding Unit 3 had recommended or performed proper and periodic inspections, NSP would have discovered the SCC before the rotor wheel failed, and such a discovery would have resulted in maintenance that would have prevented the catastrophic Unit 3 failure.

63. In sum, the investigation concluded that two factors caused the LP turbine to fail: (1) improper design and manufacture of the rotor wheel; and (2) the failure by General Electric and the General Electric-related entities to provide technical information for and service to Unit 3 that would warn NSP for itself and as Unit 3 project manager on SMMPA's behalf about SCC risks and the potential for catastrophic unit failure, that would provide adequate instruction about how to detect SCC, or that would inform NSP for itself and as project manager on SMMPA's behalf about the availability of an alternative design to mitigate those risks.

64. Until the LP turbine failed and the cause of that failure was investigated, NSP and SMMPA did not know and without advice from General Electric or a General Electric-related entity providing technical information for and service to Unit 3 could not have known about the dangerously defective condition of the LP turbine rotor wheels or

of the periodic and proper inspection of the LP turbine rotor wheels (which would include magnetic particle testing) needed to detect SCC conditions.

CAUSES OF ACTION

Count I: Fraudulent concealment

65. Before the G3 equipment and machinery that would become Unit 3 were designed and manufactured, General Electric Company knew about the risks associated with SCC in G3 type LP turbines. As time progressed, General Electric Company learned even more about systemic SCC problems in General Electric LP turbines. This knowledge would certainly have been shared with the General Electric related entities that provide technical information to and services for operators of G3 type turbines and similar equipment (as evidenced in TIL 1277-2).

66. Despite that special knowledge, during the sale and thereafter General Electric Company, the "GE" representatives at pre-outage meetings, and the General Electric-related entities performing service on Unit 3 provided incomplete information and withheld information about SCC problems from NSP for itself and as Unit 3 project manager on SMMPA's behalf.

67. Specifically, none of the defendants ever warned NSP for itself and as Unit 3 project manager on SMMPA's behalf that Wilson-Line SCC plagued G3 type LP turbines, even as instances of such problems mounted. General Electric Company went so far as to reassure NSP for itself and as Unit 3 project manager on SMMPA's behalf that proper LP rotor wheel inspections were not necessary "unless abnormal events or

operational anomalies occur." This recommendation remained in effect for almost two years after the Unit 3 catastrophic failure.

68. Despite the continued recommendation to conduct magnetic particle testing only upon the occurrence of abnormal operations or "anomalies," information available to General Electric Company, the "GE" representatives at pre-outage meetings, and the General Electric-related entities performing service on Unit 3 (but not to NSP for itself and as Unit 3 project manager on SMMPA's behalf) made the defendants aware that the periodic and proper inspections of the LP rotor wheels, later recommended in TIL 1886, were critical to prevent catastrophic unit failure and worker safety hazards.

69. General Electric was aware of dozens of similar SCC problems that had occurred over several years, many of which certainly occurred before the Unit 3 LP-B rotor wheel failed in November 2011. Nevertheless, General Electric Company intentionally withheld any information related to such failures, intentionally failed to warn about SCC-related risks in LP turbines powered by recirculating boilers, and intentionally failed to inform NSP for itself and as Unit 3 project manager on SMMPA's behalf about how to properly and timely detect SCC on LP turbine rotor wheels.

70. To make matters worse, General Electric Company and General Electric-related entities or personnel withheld information about the new patented rotor wheel dovetail design, which recognized prior design deficiencies and developed an alternative design that was less susceptible to SCC.

71. Despite being involved in planned Sherco outages, General Electric Company, the "GE" representatives at pre-outage meetings, and the General Electric-

related entities performing service on Unit 3 withheld information relating to the defective design of the existing rotor wheels and the potential for catastrophic Unit 3 failure. Despite special knowledge about SCC problems in its LP-turbine the General Electric and General Electric-related entities and personnel kept silent about the risk of failure and the means for detecting SCC while attending pre-outage meetings and submitting bids for work to be performed during Unit 3 outages.

72. Because the General Electric Company, the "GE" representatives at pre-outage meetings, and the General Electric-related entities performing service on Unit 3 withheld information about the need for periodic and proper rotor wheel testing and the potential for catastrophic Unit 3 failure and, in fact, advised NSP for itself and as Unit 3 project manager on SMMPA's behalf (expressly and through conduct) that such testing was unnecessary, NSP with reasonable diligence could not have discovered the design and manufacturing defects before the failure and ensuing investigation.

73. The General Electric Company, the "GE" representatives at pre-outage meetings, and the General Electric-related entities performing service on Unit 3 knew that NSP for itself and as Unit 3 operator on SMMPA's behalf relied upon General Electric-related entities technical information and expertise to develop maintenance and inspection plans for the LP turbines. Defendants' intentional withholding of that information rendered NSP unable to identify and detect the SCC damage that was compromising Unit 3 rotor wheel integrity.

74. Defendants' intentional, fraudulent misrepresentations, incomplete disclosure, and withholding of information directly and proximately caused damages plaintiffs in an amount well in excess of $50,000.

Count II: Willful and wanton negligence

75. A willful and wanton negligence cause of action allows for the recovery of damages for harm to a plaintiff in a position of peril when a defendant knew about the peril and had sufficient time and ability to avert the harm but because of a lack of due care failed to do so. In other words, "if a person fails to exercise ordinary care after (1) the peril was present, and (2) the peril was known to the person, his ordinary negligence rises to a higher level of negligence—*willful and wanton negligence*." *Gage v. HSM Elec. Prot. Servs., Inc.*, 655 F.3d 821, 826 (8th Cir. 2011) (emphasis added).

76. General Electric Company knew that SCC had caused steam turbines similar to Unit 3 to fail and defective LP turbine rotor wheels similar to Unit 3's to be replaced even before the installation of the Unit 3 LP turbines. Neither NSP, as a turbine purchaser, owner, and operator, nor SMMPA, as a turbine owner, was aware of the systemic SCC problems.

77. As time passed, General Electric Company acquired even more special knowledge about rotor wheel SCC in LP turbines similar to the ones at Unit 3. This knowledge would certainly have been shared with General Electric-related entities providing technical information and services to operators of G3 type turbines and similar equipment. In fact, General Electric Company and GE Energy Services warned the owners of turbines operating with "once-through" boilers about the need to periodically

inspect LP turbines for SCC but failed to warn NSP for itself and as Unit 3 project manager on SMMPA's behalf about the same SCC risks associated with the LP turbine rotor wheels in Unit 3.

78. In 2005, General Electric Company applied to patent a new rotor wheel design. The GE patent application acknowledged the inadequacy of the rotor wheel design in existing LP turbines, like Unit 3.

79. Defendants' relationship with NSP for itself and as Unit 3 project manager on SMMPA's behalf, and defendants' special knowledge, obligated them to inform NSP for itself and as Unit 3 project manager on SMMPA's behalf about SCC risks in the LP turbine.

80. General Electric Company willfully and wantonly breached an ongoing duty of care by failing to warn NSP for itself and as Unit 3 project manager on SMMPA's behalf about the rotor wheel design changes and all named defendants breached an ongoing duty of care by failing to warn NSP for itself and as Unit 3 project manager on SMMPA's behalf about the dangers associated with the former design—even as defendants participated in pre-outage meetings and bid on work to be conducted during Unit 3 outages, and in some cases performed such work.

81. In fact, by the time of the 2011 planned outage, General Electric Company had learned about numerous instances of LP turbine rotor wheel SCC damage and had certainly shared that information with General Electric-related entities providing technical information to and performing services for G3 type turbines and similar machinery and equipment. Nevertheless, at pre-outage meetings and during the bidding

process for the 2011 upgrade, "GE" representatives in attendance (including representatives of General Electric Company, GE Control Solutions, Inc. and GE International, Inc.) provided incomplete facts and failed to warn NSP for itself and as Unit 3 project manager on SMMPA's behalf about risks of which they were specifically and uniquely aware or about a more suitable and robust alternative rotor wheel dovetail design that was available.

82. In short, defendants knew NSP and SMMPA were in a position of peril and faced the potential for catastrophic unit failure as well as the threat of death or serious injury to workers but willfully and wantonly failed to avert the harm that the owners of Unit 3 faced and ultimately suffered. This willful and wanton negligence caused damages to plaintiffs well in excess of $50,000.

Count III: Gross negligence

83. An aggravated act or omission breaching a legal duty, as distinguished from the mere failure to exercise ordinary care, constitutes gross negligence. In other words, a defendant is liable in gross negligence for egregiously breaching a duty that results in damage to the plaintiff.

84. The totality of the evidence presented, rather than individual instances of conduct, determines gross negligence.

85. General Electric Company assumed a duty to design and to build a LP turbine free of defects and to ensure that any existing defects are corrected, and all defendants performing service for, providing technical assistance to and issuing technical

information on Unit 3 assumed a duty to warn NSP for itself and as Unit 3 project manager on SMMPA's behalf about potential and foreseeable risks.

86. Defendants breached those duties as follows:

a. General Electric Company knew about LP turbine SCC damage when Unit 3 was installed;

b. General Electric Company designed and manufactured rotor wheels that were destined to fail under normal operating conditions;

c. Despite special knowledge, all defendants failed to provide necessary warnings to NSP for itself and as Unit 3 project manager on SMMPA's behalf about inherent SCC risks;

d. Despite attending pre-outage meetings, bidding on outage work, and otherwise providing ongoing technical information relating to the maintenance and operation of Unit 3, defendants never warned NSP for itself and as Unit 3 project manager on SMMPA's behalf about risks inherent in the existing design and the need for proper and periodic rotor wheel inspections and maintenance;

e. Prior to the incident, General Electric Company could have replaced or recommended replacement of the rotor wheel that failed; and

f. Defendants failed to advise NSP for itself and as Unit 3 project manager on SMMPA's behalf that a replacement rotor wheel was available or that the existing rotor wheels were prone to SCC damage.

87. These facts, individually and in the aggregate, constitute gross negligence that directly and proximately caused damages to plaintiffs in an amount well in excess of $50,000.

Count IV: Professional negligence

88. Under various contracts, General Electric Company and General Electric-related entities performed engineering services on Unit 3 including LP turbine inspections. Minn. Stat. § 544.42 designates engineers as "professionals."

89. Professionals who render services must exercise such care, skill, and diligence as members of that profession ordinarily practice under like circumstances.

90. On numerous instances, defendants deviated from the applicable professional standard of care, including, but not limited to:

a. General Electric Company designed and manufactured a turbine that was unduly susceptible to SCC;

b. Defendants, while attending pre-outage meetings, bidding on outage work, and providing technical information and other engineering services, failed to provide sufficient warnings about SCC risks around the Wilson Line;

c. Defendants, while attending pre-outage meetings, bidding on outage work, and providing technical information and other engineering services failed to conduct or recommend conducting periodic and proper testing of the LP Turbine rotor wheels during the life of Unit 3; and

d. After 2005, defendants failed to replace or recommend replacing the rotor wheels even though the replacement rotor wheels were available, and failed to advise NSP for itself and as Unit 3 project manager on SMMPA's behalf that General Electric Company had developed a new rotor wheel design because designs of the type employed in the Unit 3 LP turbines was prone to SCC damage.

91. These facts, individually and in the aggregate, constitute a failure to exercise the reasonable care, skill and diligence reasonable expected of a turbine engineer. This professional malpractice directly and proximately caused damage to plaintiffs in an amount well in excess of $50,000.

Count V: Post-sale failure to warn

92. General Electric Company continues to promote, sell, and service turbines. Besides that, defendants attempted to provide customers continuing surveillance of the G3 type turbines and based upon data derived from those surveillances, defendants developed technical information and recommendations. Defendants had the opportunity to disseminate this information and to make recommendations based upon the surveillance information through TILs and through their attendance in pre-outage meetings.

93. Defendants breached an ongoing duty to warn as follows:

a. Since the early 1970s, General Electric Company knew about turbine damage, and more specifically knew about the area around the Wilson Line being vulnerable to SCC. General Electric

Company's awareness of LP turbine rotor wheel SCC problems increased throughout the 1980s, 1990s, and 2000s, as its LP turbine rotor wheels more frequently experienced SCC. This knowledge would certainly have been shared with General Electric-related entities providing technical information and services to operators of G3 type turbines and similar equipment (as evidenced in TIL 1277-2). If this special knowledge had been shared with NSP and SMMPA, proper turbine inspection and maintenance could have prevented the substantial property damage caused by SCC in the LP turbine;

b. Defendants failed to advise NSP for itself and as Unit 3 project manager on SMMPA's behalf during any outage of the potential for failure in the LP turbine rotor wheel around the Wilson Line or of the steps that could be taken to detect SCC damage and to prevent an LP turbine failure; and

c. General Electric Company's '494 patent acknowledged LP rotor wheel design deficiencies, but all of the defendants failed to adequately warn NSP for itself and as Unit 3 project manager on SMMPA's behalf either about the availability of a suitable replacement or of the potential for catastrophic failure. In fact, defendants apparently deliberately withheld such information.

94. By failing to adequately warn NSP or SMMPA about the ongoing risks—especially as defendants learned more about SCC rotor wheel problems around the Wilson Line—defendants breached the ongoing duty to warn.

95. This intentional breach of the duty to warn directly and proximately caused damages to plaintiffs in an amount well in excess of $50,000.

PRAYER FOR RELIEF

WHEREFORE, plaintiffs ask for the following relief:

1. A judgment in an amount well in excess of $50,000, plus interest; and
2. Costs and disbursements, including costs of investigation and reasonable attorney's fees.

January 27, 2014

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ACKNOWLEDGMENT

The undersigned hereby acknowledges that sanctions may be imposed pursuant to Minn. Stat. § 549.211, subd. 3.

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Attachment E8

Dakota Electric Association: FYE13 Energy Cost Over/Under-Recovery

DEA	kWh Sales (a)	MN Energy Costs (b)	MN Recovery (c)	MN Energy Costs ($/kWh) (d)	MN Recovery ($/kWh) (e)
Jul-12	200,794,181	$ 19,449,202	$ 15,951,834	0.097	0.079
Aug-12	208,441,287	$ 16,423,686	$ 16,812,189	0.079	0.081
Sep-12	172,264,387	$ 10,637,120	$ 12,076,831	0.062	0.070
Oct-12	142,715,919	$ 8,467,124	$ 9,939,034	0.059	0.070
Nov-12	136,334,166	$ 9,258,351	$ 9,514,338	0.068	0.070
Dec-12	143,065,524	$ 10,712,635	$ 9,993,776	0.075	0.070
Jan-13	160,669,639	$ 11,695,488	$ 12,122,724	0.073	0.075
Feb-13	156,589,123	$ 10,929,347	$ 11,864,611	0.070	0.076
Mar-13	142,849,544	$ 9,469,280	$ 10,671,240	0.066	0.075
Apr-13	137,564,850	$ 8,853,564	$ 10,240,980	0.064	0.074
May-13	138,580,059	$ 9,820,333	$ 10,251,526	0.071	0.074
Jun-13	141,871,744	$ 14,840,970	$ 11,932,085	0.105	0.084
FYE13	1,881,740,423	140,557,100	141,371,168	0.075	0.075

Source (a): Dakota's AAA filing, Exhibit CII, page 1 and RTA 2014 Filing, Schedule F-2 (Docket No. E111/M-14-46)

Source (b): Dakota's AAA filing, Exhibit CII, page 1.

Source (c): Dakota's AAA filing, Exhibit CII, page 1.

(d) = (b)/(a)

(e) = (c)/(a)

Total Company Recovery, July 2012 - June 2013, By Month

Month		**Minnesota Energy Costs** (a)	**Minnesota Recovery** (b)		**Over(Under) Recovery** (c)	**Over(Under) Percentage** (d)
July	$	19,449,202	$15,951,834		($3,497,368)	(17.98%)
August	$	16,423,686	$16,812,189		$388,503	2.37%
September	$	10,637,120	$12,076,831		$1,439,711	13.53%
October	$	8,467,124	$9,939,034		$1,471,910	17.38%
November	$	9,258,351	$9,514,338		$255,987	2.76%
December	$	10,712,635	$9,993,776	*	($718,859)	(6.71%)
January	$	11,695,488	$12,122,724		$427,236	3.65%
February	$	10,929,347	$11,864,611		$935,264	8.56%
March	$	9,469,280	$10,671,240		$1,201,960	12.69%
April	$	8,853,564	$10,240,980		$1,387,416	15.67%
May	$	9,820,333	$10,251,526		$431,193	4.39%
June	$	14,840,970	$11,932,085		($2,908,885)	(19.60%)
Total	**$**	**140,557,100**	**$141,371,168**		**$814,068**	**0.58%**

Source: Attachment

(c) = (b) - (a)

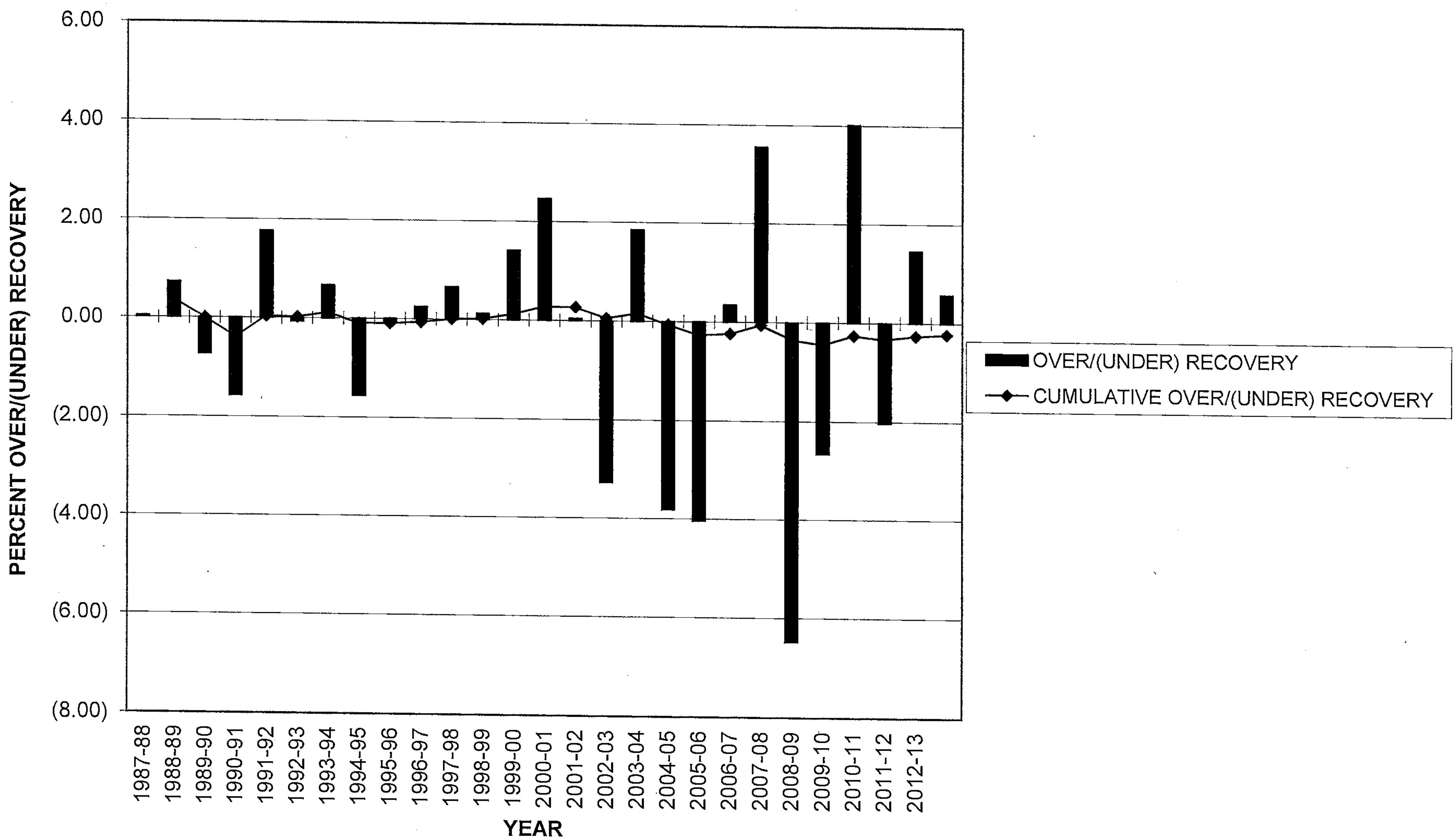
(d)= (c)/(a)

DAKOTA ELECTRIC ASSOCIATION
Summary of Fuel-Cost Recovery Since 1986-1987

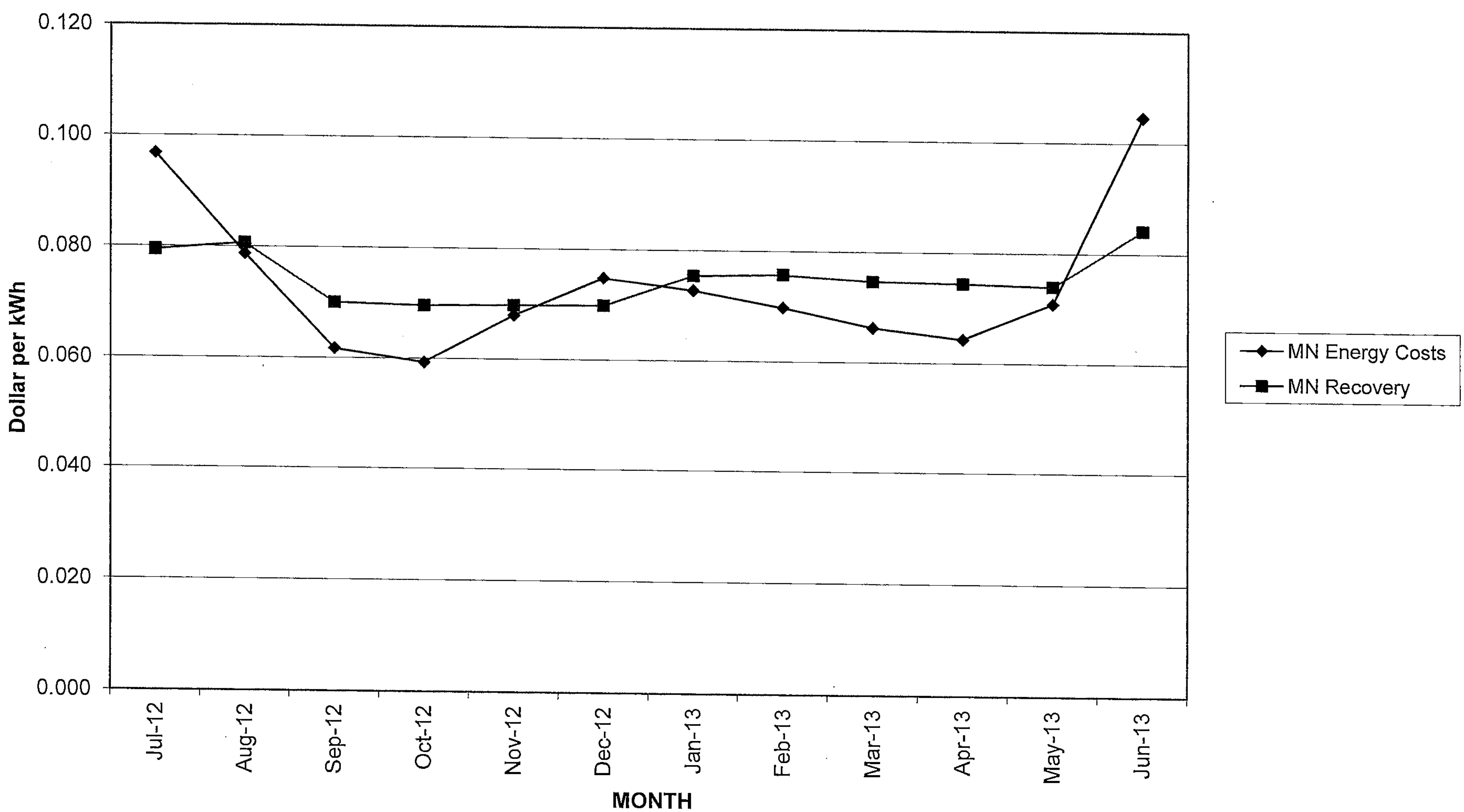
Year	Over/(Under) Recovery (%)	Cumulative Over/(Under) Recovery Average (%)	10-Year Over/Under Recovery Average (%)
1986-87	0.03		
1987-88	0.72	0.38	
1988-89	(0.74)	0.00	
1989-90	(1.57)	(0.39)	
1990-91	1.76	0.04	
1991-92	(0.07)	0.02	
1992-93	0.67	0.11	
1993-94	(1.56)	(0.10)	
1994-95	(0.08)	(0.09)	
1995-96	0.25	(0.06)	
1996-97	0.66	0.01	
1997-98	0.12	0.02	
1998-99	1.41	0.12	
1999-00	2.47	0.29	
2000-01	0.04	0.27	
2001-02	(3.27)	0.05	
2002-03	1.85	0.16	0.19
2003-04	(3.81)	(0.06)	(0.04)
2004-05	(4.04)	(0.27)	(0.43)
2005-06	0.35	(0.24)	(0.42)
2006-07	3.56	(0.06)	(0.13)
2007-08	(6.47)	(0.35)	(0.79)
2008-09	(2.66)	(0.45)	(1.20)
2009-10	4.02	(0.26)	(1.04)
2010-11	(2.02)	(0.34)	(1.25)
2011-12	1.46	(0.27)	(0.78)
2012-13	0.58	(0.23)	(0.65)

Source: Previous AAA filings up to FYE12 and table below for FYE13 data.

Energy Cost Over(Under) Recovery
Dakota Electric Association



Dakota Electric Association's Energy Costs and Recovery
July 2012-June 2013



Attachment E9

Interstate Electric: FYE13 Energy Cost Over/Under-Recovery

IPL	kWh Retail & Firm Resale (a)	kWh MN Retail Sales (b)	(RES-SN) kWh MN not subj FCA (c)		System Costs (d)
Jul-12	1,528,109,955	83,169,956	213,057	$	35,606,259
Aug-12	1,513,189,525	81,520,613	203,554	$	28,006,078
Sep-12	1,359,388,223	74,326,295	158,861	$	23,155,030
Oct-12	1,249,274,537	69,283,804	121,699	$	31,925,598
Nov-12	1,241,504,220	67,136,265	130,683	$	32,365,032
Dec-12	1,307,958,796	76,132,192	172,475	$	24,093,192
Jan-13	1,419,932,312	79,477,172	210,317	$	28,149,501
Feb-13	1,304,911,752	74,903,855	178,682	$	22,465,415
Mar-13	1,275,846,748	68,890,697	158,183	$	23,370,767
Apr-13	1,223,764,953	62,925,207	143,250	$	23,881,909
May-13	1,196,012,484	59,714,117	134,812	$	23,946,965
Jun-13	1,247,756,834	61,823,896	130,246	$	26,865,976
FYE13	15,867,650,339	859,304,069	1,955,819	$	323,831,722

MWh Sendout	16,717,254	909,836	(Source: Exhibit C, Sheet 3 of 4)
		5.4425%	

Source (a): IPL's monthly FCAs
Source (b): IPL's monthly FCAs
Source (c): IPL's monthly FCAs.
Source (d): IPL's monthly FCAs.

Minnesota Base Cost ($/kWh): 0.02465

IPL	FCA ($/kWh) (e)	Calculated FCA Recovery (f)	Base Cost Recovery (g)	MN Recovery (h)	MN Energy Costs (i)	Over(Under) Recovery (j)	MN Recovery ($/kWh) (k)	MN Energy Costs ($/kWh) (l)
Jul-12	(0.00347)	$ (290,104)	$ 2,050,139	$ 1,760,035	$ 1,937,869	$ (177,834)	0.021	0.023
Aug-12	(0.00022)	$ (20,033)	$ 2,009,483	$ 1,989,450	$ 1,524,230	$ 465,220	0.024	0.019
Sep-12	(0.00064)	$ (49,140)	$ 1,832,143	$ 1,783,003	$ 1,260,212	$ 522,791	0.024	0.017
Oct-12	(0.00373)	$ (259,256)	$ 1,707,846	$ 1,448,590	$ 1,737,550	$ (288,960)	0.021	0.025
Nov-12	(0.00684)	$ (459,694)	$ 1,654,909	$ 1,195,215	$ 1,761,466	$ (566,251)	0.018	0.026
Dec-12	(0.00354)	$ (270,714)	$ 1,876,659	$ 1,605,945	$ 1,311,271	$ 294,674	0.021	0.017
Jan-13	0.00116	$ 89,735	$ 1,959,112	$ 2,048,847	$ 1,532,036	$ 516,812	0.026	0.019
Feb-13	(0.00250)	$ (188,694)	$ 1,846,380	$ 1,657,686	$ 1,222,679	$ 435,006	0.022	0.016
Mar-13	(0.00550)	$ (379,694)	$ 1,698,156	$ 1,318,461	$ 1,271,953	$ 46,508	0.019	0.018
Apr-13	(0.00607)	$ (382,595)	$ 1,551,106	$ 1,168,511	$ 1,299,772	$ (131,261)	0.019	0.021
May-13	(0.00689)	$ (411,921)	$ 1,471,953	$ 1,060,032	$ 1,303,313	$ (243,281)	0.018	0.022
Jun-13	(0.00575)	$ (356,110)	$ 1,523,959	$ 1,167,849	$ 1,462,180	$ (294,331)	0.019	0.024
FYE13		$ (2,978,221)	$ 21,181,845	$ 18,203,624	$ 17,624,531	$ 579,094		0.021

Source (e): IPL's monthly FCAs
(f) = ((b)-(c))*(e)-0.01053*(c)
(g) = (b)*MN base cost
(h) = (f) + (g)
(i) = (d)*MN Total Retail Sales/Net Total System Sales; data from kWh sendout in IPL's FYE12 AAA filing.
(j) = (h) - (i)
(k) = (h)/(b)
(l) = (i)/(b)

Current base cost of energy of $0.02465 per kWh was approved by the Commission's June 22, 2010 Order in Docket No. E001/MR-10-277.

Total Company Recovery, July 2012 - June 2013, By Month

Month	Minnesota Energy Costs (a)	Minnesota Recovery (b)	Over(Under) Recovery (c)	Over(Under) Percentage (d)
July	$ 1,937,869	$1,760,035	($177,834)	(9.18%)
August	$ 1,524,230	$1,989,450	$465,220	30.52%
September	$ 1,260,212	$1,783,003	$522,791	41.48%
October	$ 1,737,550	$1,448,590	($288,960)	(16.63%)
November	$ 1,761,466	$1,195,215	($566,251)	(32.15%)
December	$ 1,311,271	$1,605,945	$294,674	22.47%
January	$ 1,532,036	$2,048,847	$516,812	33.73%
February	$ 1,222,679	$1,657,686	$435,006	35.58%
March	$ 1,271,953	$1,318,461	$46,508	3.66%
April	$ 1,299,772	$1,168,511	($131,261)	(10.10%)
May	$ 1,303,313	$1,060,032	($243,281)	(18.67%)
June	$ 1,462,180	$1,167,849	($294,331)	(20.13%)
Total	**$ 17,624,531**	**$18,203,624**	**$579,094**	**3.29%**

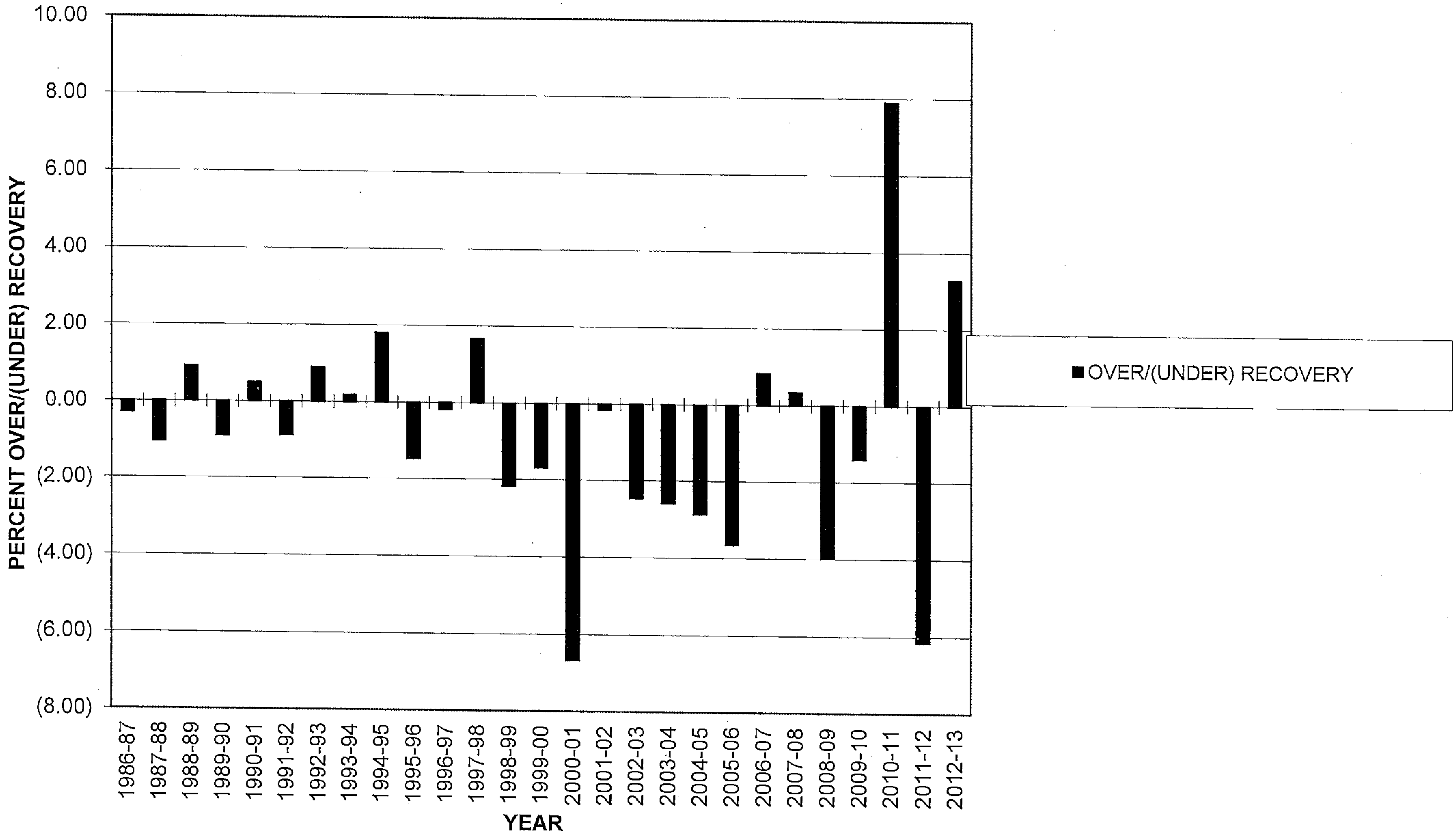
Source (a) and (b): Attachment.
(c) = (b) - (a)
(d)= (c)/(a)

INTERSTATE POWER and LIGHT COMPANY
Summary of Fuel-Cost Recovery Since 1986-1987

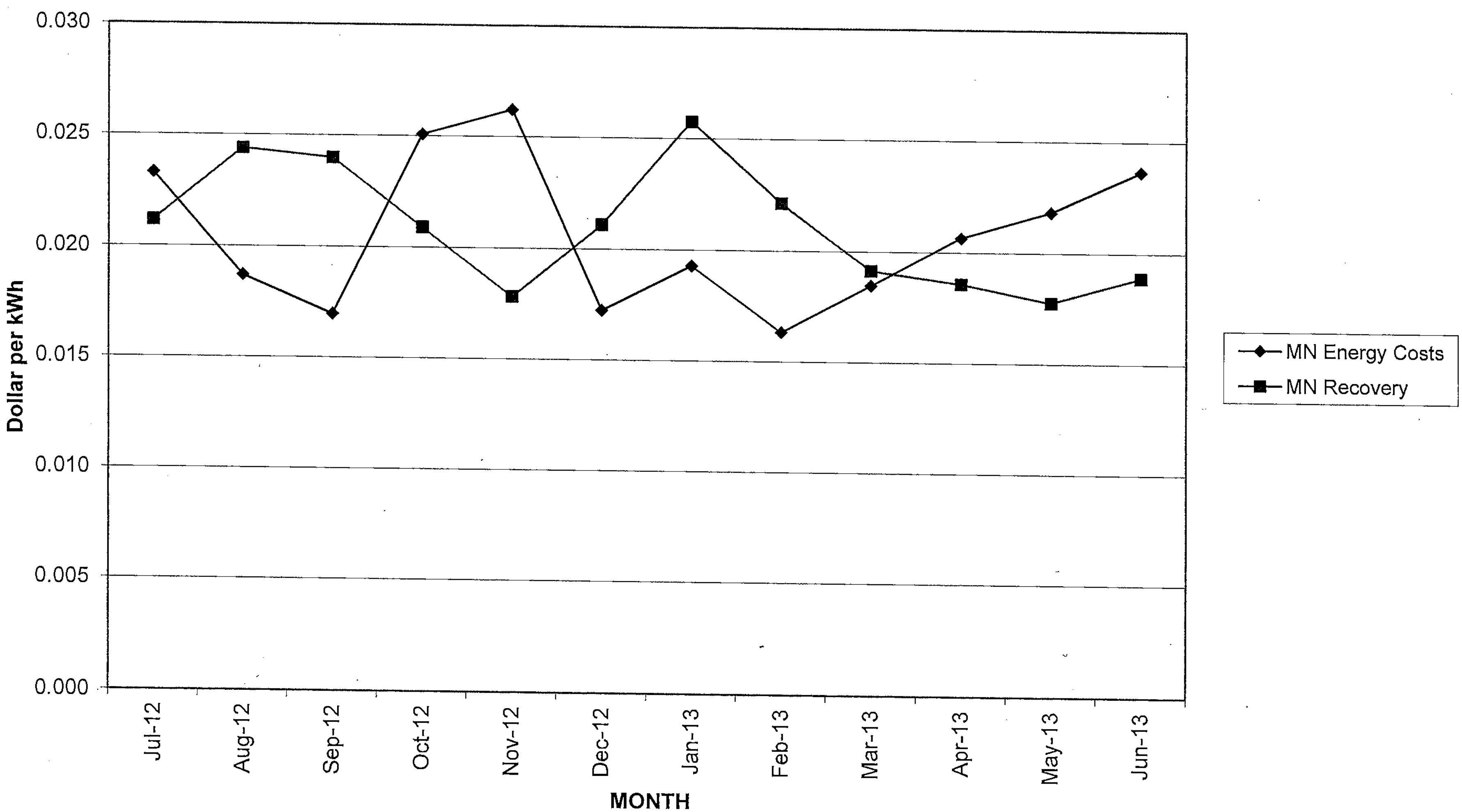
Year	Over/(Under) Recovery (%)
1986-87	(0.30)
1987-88	(1.06)
1988-89	0.91
1989-90	(0.90)
1990-91	0.49
1991-92	(0.88)
1992-93	0.89
1993-94	0.18
1994-95	1.80
1995-96	(1.47)
1996-97	(0.18)
1997-98	1.67
1998-99	(2.17)
1999-00	(1.68)
2000-01	(6.66)
2001-02	(0.16)
2002-03	(2.45)
2003-04	(2.57)
2004-05	(2.85)
2005-06	(3.64)
2006-07	0.83
2007-08	0.34
2008-09	(3.97)
2009-10	(1.40)
2010-11	7.90
2011-12	(6.14)
2012-13	3.29

Source: AAA filings

Energy Cost Over(Under) Recovery
Interstate Power and Light Company



INTERSTATE POWER and LIGHT COMPANY'S Energy Costs and Recovery
July 2012-June 2013



Attachment E10

Minnesota Power: FYE13 Energy Cost Over/Under-Recovery

MP	kWh Retail & Firm Resale (a)	FCA Retail Sales (b)	System Costs (c)
Jul-12	914,741,625	755,606,826	$20,989,445
Aug-12	910,286,369	765,421,046	$ 17,244,763
Sep-12	856,301,442	726,085,249	$ 16,897,288
Oct-12	851,966,180	711,472,948	$19,077,070
Nov-12	879,429,712	737,783,002	$ 20,897,244
Dec-12	927,737,924	770,492,081	$ 19,117,419
Jan-13	967,151,780	803,846,816	$ 21,396,847
Feb-13	892,614,449	748,773,179	$ 16,648,659
Mar-13	927,778,811	779,530,057	$ 18,158,299
Apr-13	840,132,096	709,763,599	$ 18,059,792
May-13	856,045,513	733,594,542	$ 17,817,467
Jun-13	841,733,812	714,232,569	$ 16,151,610
FYE13	10,665,919,713	8,956,601,914	$ 222,455,903

Source (a): MP's monthly FCAs
Source (b): MP's monthly FCAs.
Source (c): MP's monthly FCAs

Minnesota base cost ($/kWh): July 12 - June 13 0.01018

MP	FCA # 16 Recovery (d)	Old FCA # 16 Recovery (e)	Old FCA # 17 Recovery (f)	Base Cost Recovery (g)	MN Recovery (h)	MN Energy Costs (i)	Over(Under) Recovery (j)	MN Recovery ($/kWh) (k)	MN Energy Costs ($/kWh) (l)
Jul-12	7,338,054	$ (6)	-	$ 7,677,044	$ 15,015,092	$ 17,341,177	$ (2,326,084)	0.020	0.023
Aug-12	8,295,539	$ (50)	-	$ 7,786,880	$ 16,082,369	$ 14,497,075	$ 1,585,295	0.021	0.019
Sep-12	8,585,562	$ (262)	-	$ 7,371,647	$ 15,956,946	$ 14,325,662	$ 1,631,285	0.022	0.020
Oct-12	7,632,452	$ 1	-	$ 7,212,230	$ 14,844,683	$ 15,929,879	$ (1,085,196)	0.021	0.022
Nov-12	6,737,384	$ (5)	-	$ 7,491,215	$ 14,228,594	$ 17,529,724	$ (3,301,130)	0.019	0.024
Dec-12	8,379,373	$ -	-	$ 7,836,760	$ 16,216,134	$ 15,879,842	$ 336,292	0.021	0.021
Jan-13	10,393,963	$ -	-	$ 8,195,358	$ 18,589,321	$ 17,781,092	$ 808,229	0.023	0.022
Feb-13	8,982,247	$ -	-	$ 7,644,464	$ 16,626,712	$ 13,964,620	$ 2,662,092	0.022	0.019
Mar-13	8,729,487	$ -	-	$ 7,932,783	$ 16,662,270	$ 15,255,403	$ 1,406,867	0.021	0.020
Apr-13	7,303,904	$ -	-	$ 7,231,474	$ 14,535,378	$ 15,259,917	$ (724,540)	0.020	0.022
May-13	6,545,941	$ -	-	$ 7,452,546	$ 13,998,487	$ 15,266,102	$ (1,267,615)	0.019	0.021
Jun-13	7,340,375	$ -	-	$ 7,246,400	$ 14,586,774	$ 13,706,123	$ 880,651	0.020	0.019
FYE13	$ 96,264,282	$ (322)	$ -	$ 91,078,801	$ 187,342,761	$ 186,736,616	$ 606,145	0.021	0.021

Source (d-g): Department's calculations based on data provided in MP's monthly FCAs.
(h) = SUM(d:g)
(i)=(b)*(c)/(a)
(j) = (h) - (i)
(k) = (h)/(b)
(l) = (i)/(b)

Total Company Recovery, July 2012 - June 2013, By Month

Month	Minnesota Energy Costs (a)	Minnesota Recovery (b)	Over(Under) Recovery (c)	Over(Under) Percentage (d)
July	$ 17,341,177	$15,015,092	($2,326,084)	(13.41%)
August	$ 14,497,075	$16,082,369	$1,585,295	10.94%
September	$ 14,325,662	$15,956,946	$1,631,285	11.39%
October	$ 15,929,879	$14,844,683	($1,085,196)	(6.81%)
November	$ 17,529,724	$14,228,594	($3,301,130)	(18.83%)
December	$ 15,879,842	$16,216,134	$336,292	2.12%
January	$ 17,781,092	$18,589,321	$808,229	4.55%
February	$ 13,964,620	$16,626,712	$2,662,092	19.06%
March	$ 15,255,403	$16,662,270	$1,406,867	9.22%
April	$ 15,259,917	$14,535,378	($724,540)	(4.75%)
May	$ 15,266,102	$13,998,487	($1,267,615)	(8.30%)
June	$ 13,706,123	$14,586,774	$880,651	6.43%
Total	**$ 186,736,616**	**$187,342,761**	**$606,145**	**0.32%**

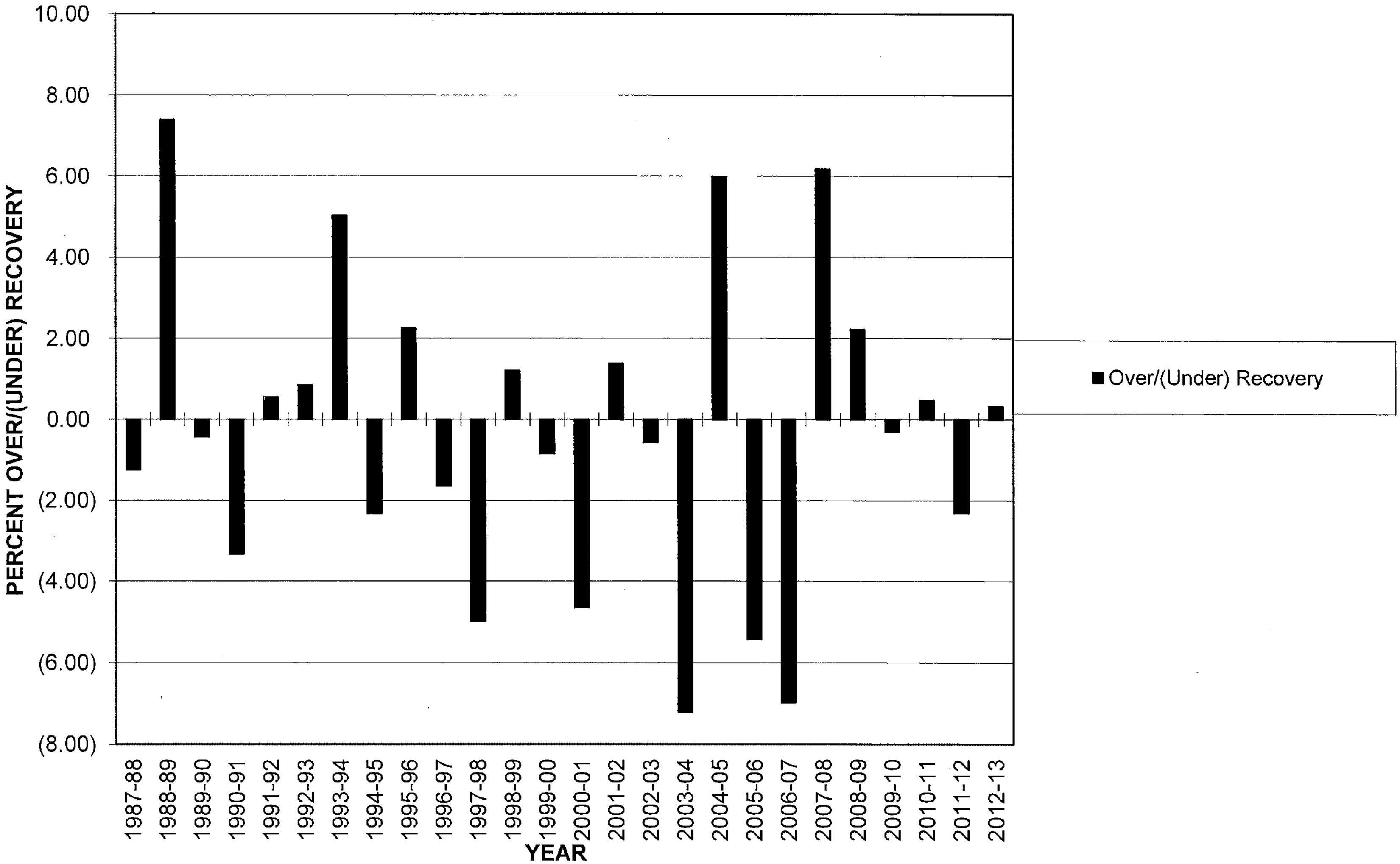
Source: Department's calculations.
(c) = (b) - (a)
(d)= (c)/(a)

MINNESOTA POWER
Summary of Fuel-Cost Recovery Since 1986-1987

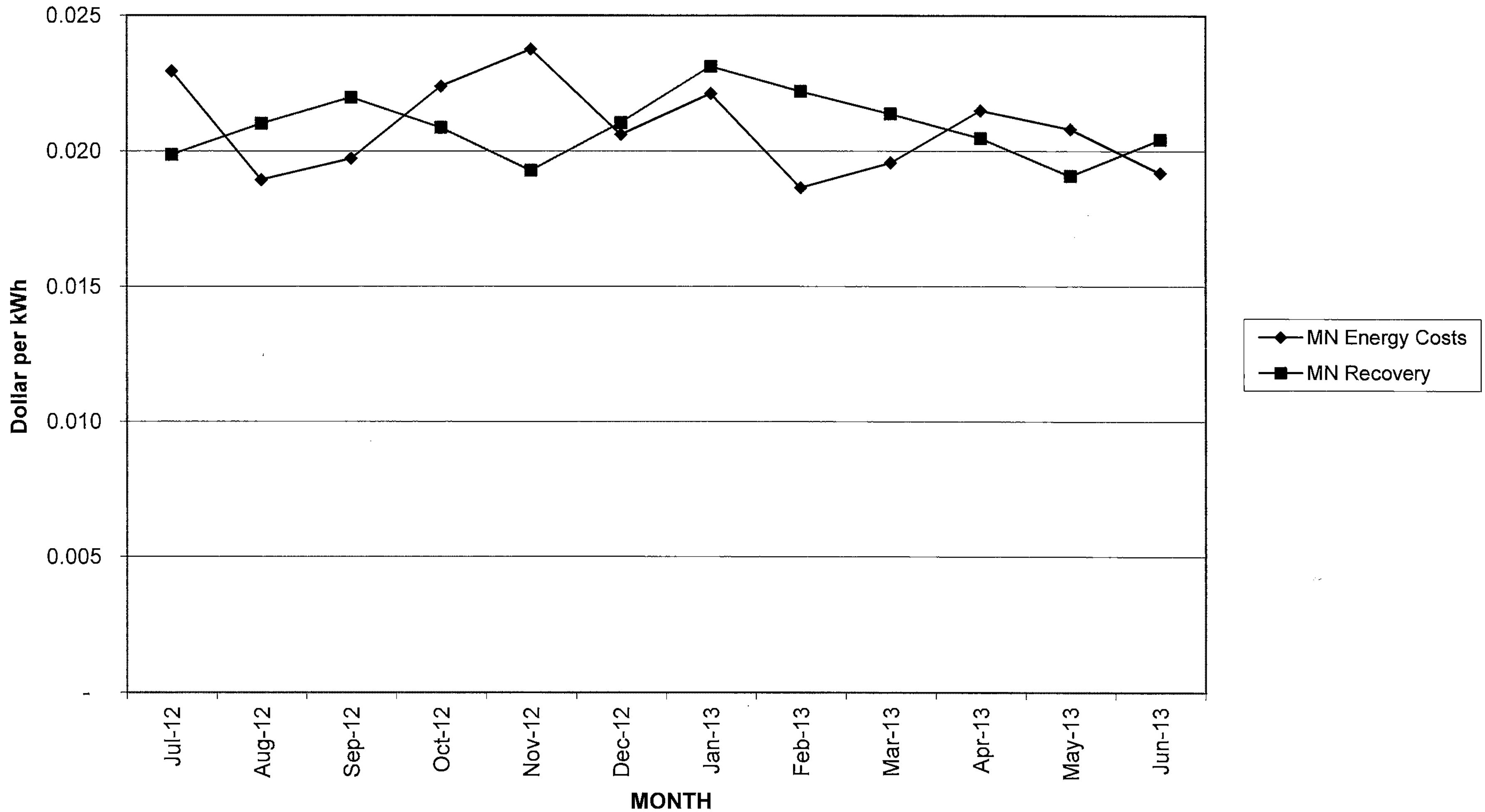
Year	Over/(Under) Recovery (%)	Cumulative Over/(Under) Recovery Average (%)	10-Year Over/Under Recovery Average (%)
1986-87	(1.82)		
1987-88	(1.24)	(1.53)	
1988-89	7.39	1.44	
1989-90	(0.43)	0.98	
1990-91	(3.33)	0.11	
1991-92	0.55	0.19	
1992-93	0.85	0.28	
1993-94	5.03	0.88	
1994-95	(2.33)	0.52	
1995-96	2.25	0.69	
1996-97	(1.63)	0.49	
1997-98	(4.98)	0.03	
1998-99	1.20	0.12	
1999-00	(0.84)	0.05	
2000-01	(4.64)	(0.26)	
2001-02	1.38	(0.16)	
2002-03	(0.56)	(0.19)	(0.51)
2003-04	(7.21)	(0.58)	(1.74)
2004-05	5.99	(0.23)	(0.90)
2005-06	(5.42)	(0.49)	(1.67)
2006-07	(6.98)	(0.80)	(2.21)
2007-08	6.17	(0.48)	(1.09)
2008-09	2.22	(0.36)	(0.99)
2009-10	(0.30)	(0.36)	(0.94)
2010-11	0.47	(0.33)	(0.42)
2011-12	(2.32)	(0.41)	(0.79)
2012-13	0.32	(0.38)	(0.69)

Source: Previous AAA filings up to June 2012 and table below for FYE13 data.

Energy Cost Over(Under) Recovery
Minnesota Power



Minnesota Power's Energy Costs and Recovery
July 2012-June 2013



Attachment E11

Otter Tail Power Company: FYE13 Energy Cost Over/Under-Recovery

OTP	kWh Retail & Firm Resale (a)	Sales Subject to FCA (kWh) (b)	System Costs (c)
Jul-12	330,600,960	168,876,204	$ 8,019,147
Aug-12	348,614,852	176,297,303	$ 9,101,414
Sep-12	327,722,015	166,631,384	$ 5,070,005
Oct-12	307,060,183	152,141,793	$ 7,964,031
Nov-12	360,276,214	169,398,136	$ 7,678,391
Dec-12	389,085,252	181,821,957	$ 11,774,347
Jan-13	459,803,141	213,098,166	$ 11,576,761
Feb-13	462,496,257	215,312,149	$ 11,261,617
Mar-13	395,660,752	186,645,298	$ 9,114,307
Apr-13	395,578,647	185,435,351	$ 7,390,756
May-13	333,188,514	156,890,826	$ 8,048,081
Jun-13	295,202,254	148,919,709	$ 6,884,442
FYE13	4,405,289,041	2,121,468,276	$ 103,883,299

Source (a): OTP's July 31, 2013 compliance report approved by the Commission's October 18, 2013 Order in Docket No. E017/M-03-30.
Source (b): OTP's July 31, 2013 compliance report approved by the Commission's October 18, 2013 Order in Docket No. E017/M-03-30.
Source (c): OTP's July 31, 2013 compliance report approved by the Commission's October 18, 2013 Order in Docket No. E017/M-03-30.

MN Base Cost (($/kWh) 0.023163

OTP	Net FCA Recovery (f)	Base Cost Recovery (g)	MN Recovery (h)	MN Energy Costs (i)	Over (Under) Recovery (j)	MN Recovery ($/kWh) (k)	MN Energy Costs ($/kWh) (l)
Jul-12	$ (74,665)	$ 3,911,680	$ 3,837,015	$ 3,861,805	$ (24,790)	0.023	0.023
Aug-12	$ 242,213	$ 4,083,574	$ 4,325,787	$ 4,382,995	$ (57,208)	0.025	0.025
Sep-12	$ 213,709	$ 3,859,683	$ 4,073,392	$ 2,441,578	$ 1,631,814	0.024	0.015
Oct-12	$ 307,829	$ 3,524,060	$ 3,831,889	$ 3,835,262	$ (3,373)	0.025	0.025
Nov-12	$ (373,169)	$ 3,923,769	$ 3,550,600	$ 3,697,706	$ (147,106)	0.021	0.022
Dec-12	$ (476,081)	$ 4,211,542	$ 3,735,461	$ 5,670,208	$ (1,934,747)	0.021	0.031
Jan-13	$ 53,403	$ 4,935,993	$ 4,989,396	$ 5,575,056	$ (585,660)	0.023	0.026
Feb-13	$ 597,792	$ 4,987,275	$ 5,585,067	$ 5,423,291	$ 161,777	0.026	0.025
Mar-13	$ 804,696	$ 4,323,265	$ 5,127,961	$ 4,389,204	$ 738,757	0.027	0.024
Apr-13	$ 297,695	$ 4,295,239	$ 4,592,934	$ 3,559,189	$ 1,033,745	0.025	0.019
May-13	$ 90,149	$ 3,634,062	$ 3,724,211	$ 3,875,739	$ (151,527)	0.024	0.025
Jun-13	$ (340,178)	$ 3,449,427	$ 3,109,249	$ 3,315,361	$ (206,112)	0.021	0.022
FYE12	$ 1,343,393	$ 49,139,570	$ 50,482,963	$ 50,027,392	$ 455,570		0.024

Source (f): OTP's July 31, 2013 compliance report approved by the Commission's October 18, 2013 Order in Docket No. E017/M-03-30.
(g) = (b)*MN base cost
(h) = (f) + (g)
(i) = (c)*Total Revised Sales Subject to FCA/Net Total System Sales
(j) = (h) - (i)
(k) = (h)/(b)
(l) = (i)/(b)

Note:
Current base cost of energy of $0.023163 per kWh was approved by the Commission's May 27, 2010 Order in Docket No. E017/MR-10-240.

Total Company Recovery, July 20102- June 2013, By Month

Month	Minnesota Energy Costs	Minnesota Recovery	Over(Under) Recovery	Over(Under) Percentage
	(a)	(b)	(c)	(d)
July	$ 3,861,805	$3,837,015	($24,790)	(0.64%)
August	$ 4,382,995	$4,325,787	($57,208)	(1.31%)
September	$ 2,441,578	$4,073,392	$1,631,814	66.83%
October	$ 3,835,262	$3,831,889	($3,373)	(0.09%)
November	$ 3,697,706	$3,550,600	($147,106)	(3.98%)
December	$ 5,670,208	$3,735,461	($1,934,747)	(34.12%)
January	$ 5,575,056	$4,989,396	($585,660)	(10.51%)
February	$ 5,423,291	$5,585,067	$161,777	2.98%
March	$ 4,389,204	$5,127,961	$738,757	16.83%
April	$ 3,559,189	$4,592,934	$1,033,745	29.04%
May	$ 3,875,739	$3,724,211	($151,527)	(3.91%)
June	$ 3,315,361	$3,109,249	($206,112)	(6.22%)
Total	**$ 50,027,392**	**$50,482,963**	**$455,570**	**0.91%**

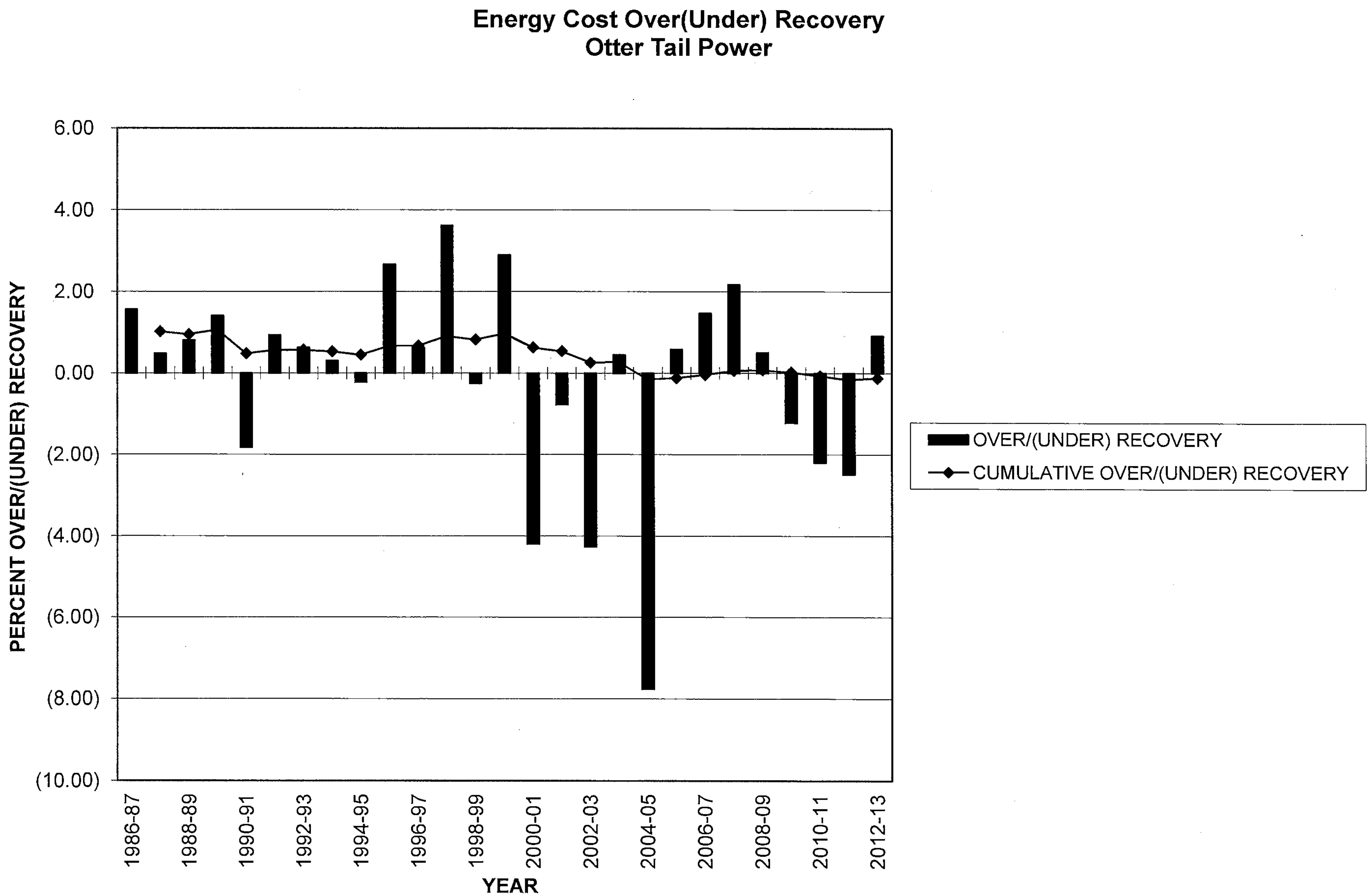
Source: Attachment.
(c) = (b) - (a)
(d)= (c)/(a)

OTTER TAIL POWER COMPANY

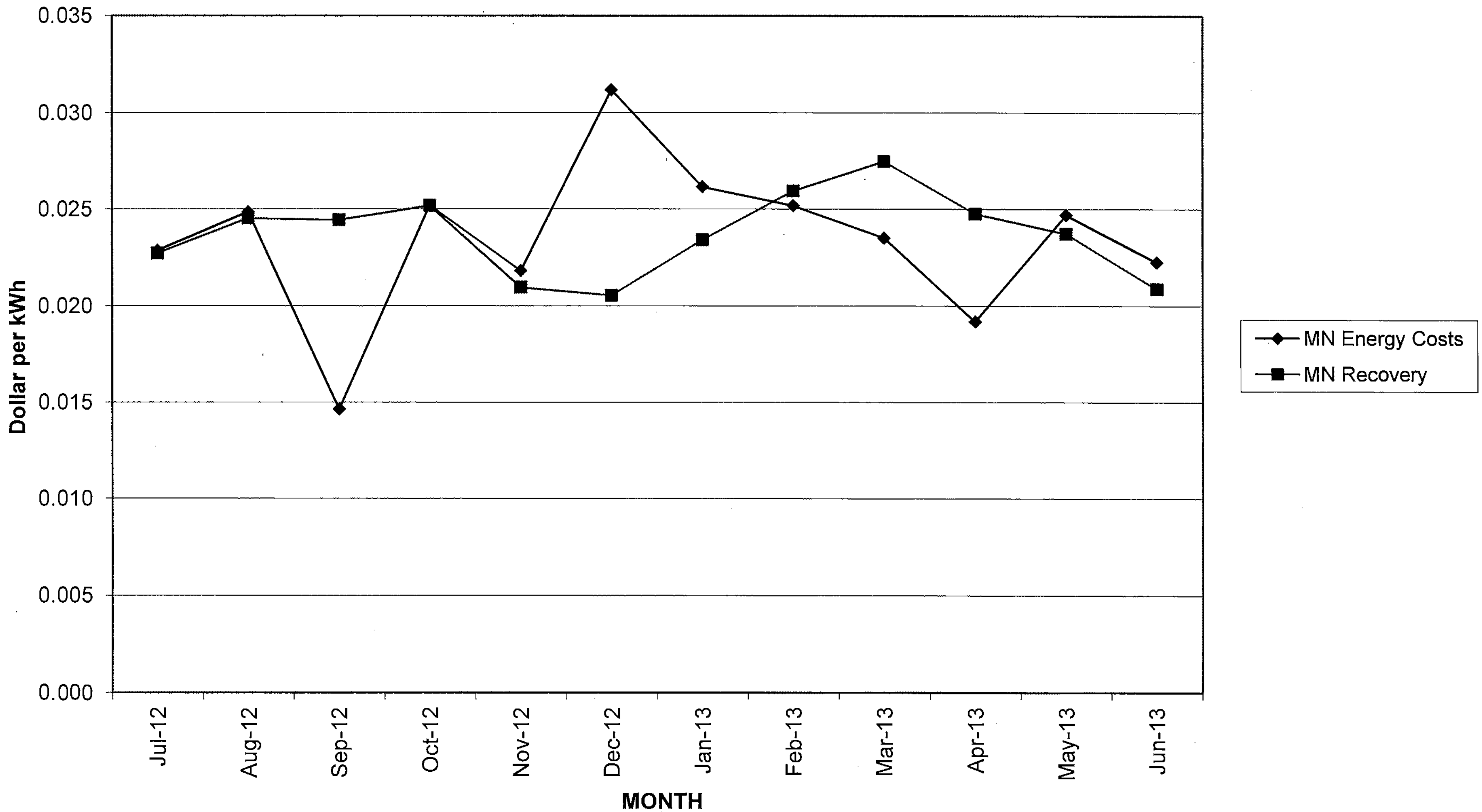
Summary of Fuel-Cost Recovery Since 1986-1987

Year	Over/(Under) Recovery (%)	Cumulative Over/(Under) Recovery Average (%)	10-Year Over/Under Recovery Average (%)
1986-87	1.56		
1987-88	0.48	1.02	
1988-89	0.80	0.95	
1989-90	1.41	1.06	
1990-91	(1.83)	0.48	
1991-92	0.93	0.56	
1992-93	0.62	0.57	
1993-94	0.30	0.53	
1994-95	(0.22)	0.45	
1995-96	2.67	0.67	
1996-97	0.63	0.67	
1997-98	3.62	0.91	
1998-99	(0.25)	0.82	
1999-00	2.90	0.97	
2000-01	(4.19)	0.63	
2001-02	(0.77)	0.54	
2002-03	(4.26)	0.26	0.04
2003-04	0.44	0.27	0.06
2004-05	(7.76)	(0.15)	(0.70)
2005-06	0.58	(0.12)	(0.91)
2006-07	1.47	(0.04)	(0.82)
2007-08	2.17	0.06	(0.97)
2008-09	0.50	0.08	(0.89)
2009-10	(1.22)	0.02	(1.30)
2010-11	(2.20)	(0.06)	(1.11)
2011-12	(2.49)	(0.16)	(1.28)
2012-13	0.91	(0.12)	(0.76)

Source: Previous AAA filings up to June 2012 and previous table for FYE13 data.


Energy Cost Over(Under) Recovery
Otter Tail Power
6.00
4.00
2.00
0.00
(2.00)
(4.00)
(6.00)
(8.00)
(10.00)
PERCENT OVER/(UNDER) RECOVERY
1986-87
1988-89
1990-91
1992-93
1994-95
1996-97
1998-99
2000-01
2002-03
2004-05
2006-07
2008-09
2010-11
2012-13
YEAR
OVER/(UNDER) RECOVERY
CUMULATIVE OVER/(UNDER) RECOVERY

OTTER TAIL POWER COMPANY'S Energy Costs and Recovery
July 2012-June 2013



Attachment E12

Xcel Electric: FYE13 Energy Cost Over/Under-Recovery

	Jul 12-Dec 12	Jan 13-Jun 13
Minnesota Base Cost ($/kWh):	0.02703	0.02729

Xcel	Prior Balance (a)	True Up Recovery (b)	FCA Recovery (c)	Base Cost Recovery (d)	Fuel Clause Revenues (e)	MN Energy Costs (f)	Saver's Switch True Up Adj (g)	Balance (Cost-Revenues) (h)
Jul-12	$ 7,002,045	$ 7,823,997	$ (5,455,995)	$ 90,470,606	$ 92,838,608	$ 96,998,683	$ 33,053	$ 11,195,173
Aug-12	$ 5,256,254	$ 5,253,206	$ (2,945,355)	$ 78,820,846	$ 81,128,697	$ 80,639,132	$ 48,413	$ 4,815,102
Sep-12	$ 11,195,173	$ 11,136,627	$ (3,681,600)	$ 67,242,502	$ 74,697,529	$ 63,548,942	$ 117,064	$ 163,650
Oct-12	$ 4,815,102	$ 4,916,468	$ (4,213,954)	$ 67,005,335	$ 67,707,850	$ 67,302,695	$ -	$ 4,409,947
Nov-12	$ 163,650	$ 170,300	$ (149,708)	$ 67,447,508	$ 67,468,100	$ 68,456,764	$ -	$ 1,152,315
Dec-12	$ 4,409,947	$ 4,392,588	$ (200,566)	$ 67,771,237	$ 71,963,259	$ 73,325,609	$ -	$ 5,772,297
Jan-13	$ 1,152,315	$ 1,150,604	$ -	$ 70,238,166	$ 71,388,770	$ 70,304,656	$ -	$ 68,201
Feb-13	$ 5,772,297	$ 5,674,805	$ (1,211,512)	$ 62,381,321	$ 66,844,613	$ 62,189,862	$ -	$ 1,117,546
Mar-13	$ 68,201	$ 69,556	$ (200,501)	$ 68,397,614	$ 68,266,668	$ 74,099,811	$ -	$ 5,901,343
Apr-13	$ 1,117,546	$ 1,153,450	$ 2,731,362	$ 63,168,944	$ 67,053,756	$ 73,159,370	$ -	$ 7,223,160
May-13	$ 5,901,343	$ 5,903,282	$ 8,571,071	$ 64,973,799	$ 79,448,152	$ 73,352,662	$ -	$ (194,147)
Jun-13	$ 7,223,160	$ 7,137,702	$ 7,295,651	$ 71,106,609	$ 85,539,962	$ 80,109,945	$ 180,323	$ 1,973,465
FYE13		$ 54,782,585	$ 538,893	$839,024,487	$894,345,964	$883,488,131		

1. FYE13 cumulative under-recovery	$ 1,779,319
2. FYE12 cumulative under-recovery	$ 12,258,299
3. FYE13 under-recovery = (1)-(2)	$ (10,478,980)
	1.19%

(a) = (h) with a two-month lag.
Source (b), (c), (d) & (f): Xcel's monthly FCA data with further Department calculations under the Department's review of the monthly FCAs.
(e) = (b) + (c) + (d)
Source (g): Xcel's monthly FCAs. More info on the Saver's Switch discount program is provided in Xcel's May 7, 2007 Supplemental Information Compliance filing in Docket No. E002/GR-05-1428.
(h) = (a) - (e) + (f) + (g)

Note:
Xcel's FCA factor is the ratio of (system costs - intersystem sales - Windsource costs) by (system retail MWh, resale MWh and Windsource MWh).
Minnesota costs are the product of the FCA factor by MN sales (MWh) subject to FCA factor (retail minus Windsource).
Xcel's FCA revenues are calculated on the basis of MN sales (MWh) subject to FCA factor.

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Public Review of the 2012-2013 Annual Automatic Adjustment Reports

Docket No. **E999/AA-13-599**

Dated this 16th day of September 2014

/s/Sharon Ferguson

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Marie	Doyle	marie.doyle@centerpointenergy.com	CenterPoint Energy	800 LaSalle Avenue P O Box 59038 Minneapolis, MN 554590038	Electronic Service	No	OFF_SL_13-599_13-599
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John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes	OFF_SL_13-599_13-599
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